National Grid Transmission
RIIO-T1: Initial Proposals consultation response
Supplementary information – System Operator costs

Table of contents

Executive summary 2

Document structure 3

Electricity SO capex 4

Specific SO capex schemes 4

Gas SO capex 15

Capability enhancements 15

Asset health investments 16

EU regulatory requirements 17

SO Opex allowances 19

SO Uncertainty Mechanisms 28

Detailed review of PPA arguments 31

Introduction 31

Electricity and Gas Joint Issues 31

Electricity Issues 33

Gas Issues 41

Executive summary

1 The Initial Proposals for the SO do not consider the impact of uncertainty on external SO costs or system risk and incorporate analysis errors in the opex assessment. The resulting allowances incentivise us to only focus on minimising internal costs to the detriment of much larger balancing and constraint costs which will have more of an impact on consumers.

2 Efficient operation of the transmission networks is dependent on the timely provision of required capabilities within the SO, however the Initial Proposals:

(a) **Reduce allowances due to uncertainty**: while not including any mechanism to manage that uncertainty, in direct contrast to Ofgem's consultant's recommendation. This will increase balancing and constraint costs as a result.

(b) **Arbitrarily defer investments**: from the second half of the period without considering the impact on external SO costs or the risk involved as older systems are left in operation

(c) **Incorporate analysis errors**: with opex allowances incorrectly assuming that these costs are linearly linked to capex

3 As outlined in detail within our March submissions, the operational environment is expected to substantially change for both our gas and electricity SO roles during the RIIO-T1 period as decarbonisation of the energy supply chain leads to greater volatility and variability of power and gas flows. To deliver against these operational challenges, and continue to deliver the outputs that our stakeholders require, we proposed plans that take a balanced approach, optimising between external SO costs, investing in process development, commercial change, IT systems, physical TO assets and people. However, the Initial Proposals seem to include little regard for total costs or risk, instead focusing on reducing internal SO costs without taking into account the detrimental impact on balancing and constraint management costs that these reductions will create.

4 As an eight-year price control, RIIO-T1 requires a different approach to a more traditional five-year control. There is inherently a greater level of uncertainty in terms of how we will overcome the future challenges of system operation over the second half of the period than over the first. Ofgem's assessment takes no account of this, and instead proposes that investments in the last few years of the period are arbitrarily removed or deferred into the next price control period. This approach will increase the overall costs of system operation if we do not have access to funding to both develop innovative solutions to the challenges that are coming, and to refresh our existing capabilities in a timely manner.

5 Whilst recent conversations with Ofgem suggest that some of this risk can be covered by an uncertainty mechanism based around the mid-period review, this is neither explicit in the Initial Proposals nor adequately defined for us to be comfortable with this approach. If Ofgem believes - as its consultants propose - that all allowances cannot be set on an ex ante basis in such a dynamic operational environment, we need to work with Ofgem to develop an appropriate mechanism. This will act to protect both end consumers and the SO from future uncertainty by avoiding unnecessary delays in the development and delivery of important innovations to minimise total SO costs.

6 Notwithstanding the development of this mechanism, ex ante allowances should be corrected to reflect appropriate risk-based analysis relating to the efficient refresh and enhancement of our IT assets to ensure we can avoid undue risk of system failure and significant increases in system support charges.

Document structure

7 We have answered the high level questions in regards to the proposed allowances that have been granted for our System Operator (SO) forms of control within our main response to the initial proposals. This document has been produced to give more detailed supplementary information in support of our response to these questions.

8 Within this document we cover both our gas and electricity SO roles and address the concerns that we have with the PPA documentation which has been used as the basis for Ofgem's initial proposals for the SO. We also reiterate the main factual inaccuracies that we provided to Ofgem after our initial review of PPA's document, which appear not to have been corrected in the final draft.

9 The first two chapters of this annex provide evidence to support the funding of specific schemes on an ex ante basis. Further details are then presented to support the opex allowances that we submitted in March. In recognising the uncertainty associated with some aspects of our original submission, we then review the requirement for appropriate uncertainty mechanisms. Finally we have included further evidence in direct response to some of the specific concerns that were raised by PPA within their report.

Electricity SO capex

Specific SO capex schemes

10 Within our submission, we highlighted a step change to our approach to delivery of IT projects. We have moved away from stand alone IT solutions to focus on delivery of the required capabilities within a programme of work.

11 The investments have been selected on their merits and justified through the leverage of benefits for customers (early system access, more capacity, reduced balancing costs), taking into account the evolving GB physical networks and regulatory regimes. This will provide the necessary capability and asset replacement to ensure the system remains secure and safe to operate.

12 We have reviewed the allowances and deductions that PPA have suggested within their 'case 1' analysis. We are subsequently concerned that these inadequate allowances will jeopardise our ability to operate the transmission network securely and reliably whilst minimising the costs to the industry, and subsequently consumers, of balancing the system. What follows is further details of the needs case and rationale for ex ante funding for certain schemes. The table below summarises these.

Scheme Name £m(9/10)	March Submission	Ofgem Initial Proposals	Revised request	Reason
Stability Control	[text deleted]	[text deleted]	[text deleted]	Provision of funding for least regrets stability monitoring capability to monitor reliability of network and minimise reserve holding requirements
EBS Phase 2	[text deleted]	[text deleted]	[text deleted]	Incorporation of stakeholder-led developments that were requested for phase 1, including provision of industry standard AGC technology
Wokingham Smart Workplace	[text deleted]	[text deleted]	[text deleted]	Initial Proposals disallow to allow more research but concept has already been proven in Warwick office
Improved Modelling	[text deleted]	[text deleted]	[text deleted]	Enhanced capability to optimise network configuration, reducing balancing costs
OLTA Hardware refresh	[text deleted]	[text deleted]	[text deleted]	Maintains ability to study more network configurations, a process which was supported by PPA
IEMS Future upgrade	[text deleted]	[text deleted]	[text deleted]	Work during development lead time of critical system refresh needs to be funded
Infrastructure for business systems	[text deleted]	[text deleted]	[text deleted]	Increased costs compared to TPCR4 period driven by headcount allocations
SMART Demand	[text deleted]	[text deleted]	[text deleted]	Required to be able to forecast shifting intraday demand patterns and facilitate greater demand side response provision

INVP 2465 Stability Control System

Least regrets expansion of our stability monitoring capability should be funded ex-ante to minimise reserve holding requirements and balancing costs

13 PPA have proposed a reduction of £18.4m for INVP 2465 Stability Control, but have accepted the case for stability monitoring based on the fact that it is not clear about what extent wind generation will be able to contribute to inertia. Funding of INVP 0721 (funded within Initial Proposals) is required for monitoring, however, this investment line only refers to the asset refresh of the existing limited power system stability monitoring system. We

will need to expand and develop our capability in stability monitoring to minimise costs for maintaining reliability. In addition, we need to understand and increase capabilities in the area of stability analysis and voltage assessment. All these enhancements fall within the investment line of INVP 2465 Stability Control System we submitted in March.

14 The Initial Proposals disallow this investment as ‘it is considered that there is considerable scope provided by the intra-DC facility coupled with series compensation to manage stability issues’. This seems to take the view that the main cost in this area is for a control system, whereas a substantial proportion of the investment is in these initial areas. To illustrate this we have split the original investment line into the various elements, proposing that a total of [text deleted] is allowed ex-ante for these near term requirements. Due to the uncertainty surrounding required future investments in managing stability issues, any further funding should be dealt with by an SO uncertainty mechanism (see later section).

Stability Monitoring

15 The existing Power System Stability monitoring system measures the small-signal stability/oscillation of synchronous machines by analysing the digital output from Phasor Measurement Units (PMU) strategically located across the England & Wales (E&W) transmission network at high data sample rates.

16 There are currently nine operational PMUs on the E&W transmission network. The PMU data from the substations is sent via the existing Wide Area Network (WAN) to the Phasor Data Concentrator (PDC) server located at the ENCC for analysis and reporting of any instability occurrences. This work stream will expand the breadth of coverage of our capability for wide area stability monitoring allowing us to utilise the maximum capacity of the existing systems.

17 The increase will be delivered by connecting to additional PMUs on the E&W transmission network delivered by the TO, some of which will be delivered as part of the Thyristor-Controlled Series Capacitors (TCSC) installation programme and the Western HVDC link project.

18 This work stream will also provide interfaces to monitor stability directly from the Scottish TO systems. We currently have no visibility of any PMU data from within Scotland. Recent discussions with the Scottish TO’s have identified that Scottish Power (SP) currently have approximately six PMUs on their transmission network with plans to increase this number to twenty by the end of 2012. SHETL currently have no PMUs located on their transmission network but plan to install at least thirteen over the next eight years.

£m(9/10)	Investment Phasing								
Work stream	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	Total
Stability Monitoring	0.5	0.5	0.5	0.5	-	0.6	-	-	2.6

Disaster Recovery and Data Management

19 The utilisation of PMUs requires IT services to support their effective operation. The existing IT infrastructure was not designed to support the increasing data volumes or the renewed scope of stability monitoring and ultimately control. We plan to enhance our

communication links and build in redundancy and disaster recovery capabilities, for example by moving PMU's onto a resilient operational network.

20 The increase data flows will require greater management of data. We are proposing development of an interface/middleware for this data with the existing ESO Data Historian system for long term storage, reporting and improved visualisation.

£m(9/10)	Investment Phasing								
Work stream	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	Total
DR & DM	0.4	0.4	0.4	0.4	-	-	-	-	1.6

Stability Analysis

21 Stability analysis is used to identify credible faults on the network which will lead to instability. Instability occurrences happen very fast, disallowing manual intervention, so the only possible solutions to these stability constraints are costly re-despatch of generation or arming operational tripping schemes that trip generation should a specific event occur. The number of these inter-tripping schemes is currently in excess of 30 and planned to double in the next few years to allow faster connection of new generation to the transmission system.

22 Wind generation can fluctuate from high output to zero over a short period of time. Similarly interconnectors can change their flow from full import to full export and vice versa in seconds. This can have a significant impact on power flows around the transmission network. This work stream aims to expand the current in-flight project INVP 2471 - Online Stability Analysis (OSA). The OSA project will deliver the ability for automated analysis of the network (e.g. every 15 minutes) using metered, modelled data (from the state estimator) and current inter-trip selections. The inter-trip selections are flexible but complex and often require the selection of up to ten trigger events and up to four resultant actions. These tripping schemes are manually selected following modelling. Enhanced capability is required to provide advice to our engineers on how these schemes should be optimally set both at the planning stage and in real time

23 A synchronous generator has a different oscillatory response to an event depending on the amount of load it is carrying; this means that a generator which is half loaded would return faster to its steady-state point as opposed to a generator that is fully loaded. This work stream will provide inter-trip advice that takes account of actual generator outputs in order to maximise network utilisation. This will help maximise the benefit of intertrip schemes in helping to reduce stability related constraint costs.

24 The installation of HVDC and TCSC assets will enable us to control bulk transfer of power and the voltage profile in a localised area, and in doing so maximising the transfer capability at these boundaries. Our online stability assessment capability will be enhanced to determine optimal set points for all TCSCs and HVDCs to maximise the benefits from these significant TO investments.

£m(9/10)	Investment Phasing								
Work stream	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	Total
Stability Analysis	1.0	2.0	2.4	2.4	-	-	-	-	7.8

Voltage Stability Assessment

25 Voltage instability is an uncontrolled decrease in voltage, triggered by a small disturbance (as opposed to a large disturbance, i.e. fault), leading to voltage collapse in a wide area of the network and is primarily caused by dynamics related with the load and the transfer of large amounts of power. Voltage collapse may happen even if the initial operating voltages are at acceptable levels, so voltage metering does not indicate the proximity to voltage collapse point, especially in heavily compensated areas. Voltage instability and collapse may occur in a time frame of a few minutes, leaving insufficient time for corrective actions. This work stream is independent from the previous angular stability monitoring and analysis as it is not related with oscillation of synchronous machines.

26 We need to develop our voltage assessment capability through a tool for offline voltage collapse assessment taking into account the dynamically changing voltage and load.

£m(9/10)	Investment Phasing								
Work stream	13/14	14/15	15/16	16/17	17/18	18/19	19/20	20/21	Total
Voltage Stability Assessment	-	-	0.5	0.5	-	-	-	-	1.0

27 In summary we are proposing an ex-ante funding of £13m to cover the enhancements of our capabilities provided by the above four areas covered by INVP 2465, to manage stability and maximise the physical capacity of the transmission network. In addition we are proposing that any additional funding is covered within the ESO uncertainty mechanism.

INVP 1420 EBS (Electricity Balancing System) Phase 2

Stakeholder-led investments which could not be incorporated into phase 1 should be brought back into RIIO-T1 funding rather than deferred to RIIO-T2

28 PPA has stated that EBS Phase 2 should be delayed by two years, allowing more time to clarify requirements against the build up of wind. This reduction moves £3.8m out of the RIIO-T1 period. Without the timely investment in the second phase of this project, our ability to optimise the economic despatch of the broadest set of market participants will be compromised leading to sub optimal economic despatch.

29 EBS is a significant development by ABB for us and is not only driven by the increased wind generation but also by introducing industry best practice in automation and innovation in the area of analysis capabilities for secure economical balancing of the transmission system. The EBS will be more configurable than the current Balancing

Mechanism system with faster implementation times for certain changes (e.g. new data reporting). The main benefits are:

(a) **Security of supply:** Our primary aim is to maintain security of supply. EBS Phase 2 programme of work will allow the analysis of a range of credible scenarios, for example assessing the impact on security and balancing costs of a +5% or -5% change nationally or regionally in demand levels, in wind output, in interconnector transfers and generation offer prices. By ensuring we remain in an acceptable operating envelope for a range of credible inputs we will be able to make the best overall decisions to minimise costs and protect system security.

(b) **Stakeholder-led requirements:** In the stakeholder engagement we undertook in advance of phase 1 of the EBS replacement stakeholders proposed several improvements which we were not able to incorporate. The second phase allows these improvements to be put into operation. We have frequent meetings with industry users of the Balancing Mechanism and we have agreed with the market participants what developments in Phase 2 will follow on from the initial EBS go-live Phase 1 delivery. These developments include new modern interfaces, modelling of multi shaft CCGTs and time varying dynamic parameters. We will continue to build on these deliverables across RIIO-T1.

(c) **Voltage constraints:** We have seen a considerable rise in constraint costs in recent years and an important deliverable of EBS Phase 2 is to develop the network secured functionality to assess voltage constraints. Voltage constraints are an increasing cost driver. This work will be world leading and innovative in nature and hence it is essential that development begins at the earliest possible opportunity to ensure customer benefits are realised as soon as possible. This aligns with stakeholder views expressed at the London workshop on September 4th, suggesting that investments that reduced constraint costs were an entirely appropriate focus.

(d) **Frequency control:** is becoming increasingly difficult with intermittent generation levels increasing (mostly wind) and an associated decrease in system inertia leading to a more volatile system. Frequency response (automatic primary despatch) is progressively more utilised in damping the system frequency before bid-offer acceptances (BOAs) can be used to deal with the imbalances (manual secondary despatch). Therefore the requirements for frequency response are increasing.

(e) **Automated reserve despatch:** It is estimated that on average £25m per annum of response costs are needed due to the absence of a system to automate secondary reserve despatch such as Automatic Generator Control (AGC). Our standard deviation of system frequency is 0.06Hz compared to Ercot in Texas, a similar islanded system with AGC, which has a standard deviation of only 0.02Hz. With our largest loss set to increase from 1320MW to 1800MW by 2014, the additional costs of the safety margin required due to our standard deviation alone are forecast to be some £60m per annum by 2020.

30 The EBS Phase 2 investment will seek to take AGC (which is commonly used by international TSOs) to a new level of economic optimisation by linking AGC on our EMS with our 5 minute re-optimised outputs from the EBS despatch algorithm. AGC costs can be off-set against the savings in our safety margin levels and will reduce the wear and tear on generator governors that are selected to provide frequency containment response (which is a common complaint for the generators and constitutes a cost of providing this service). AGC will also give us the capability to implement tie line (Area Control Error, ACE) control across key constraint boundaries like the Scottish export boundary. This will

allow us to precisely control the output of a generator within the exporting area to maintain a close tolerance on the limit, thereby reducing the need for a margin on the limit and so helping to contain balancing costs without compromising security. This is particularly important in a constrained group that contains lots of variable generation as is the case with Scottish wind. We have already started the initial scoping of the work in this area to automate secondary reserve despatch.

31 During the industry consultation conducted in 2008 for the EBS project the industry expressed their concerns with National Grid issuing a higher volume of BOAs. This EBS Phase 2 development will seek to work with the generating companies to deliver a capability to automate the acceptance and enactment of our instructions and so allow an increase in the total number of BOAs we can issue with shorter durations. This will lead to the potential for lower balancing costs and improved (faster) recovery from system events, allowing us to further exploit the short term ratings on our transmission circuits.

32 Data provision: In addition to the above development areas in EBS Phase 2, there will be work to improve data provision with other transmission control, planning and analysis systems. EBS phase 2 is not exclusively driven by increased wind generation but will be developed to respond to developments in Smarter Transmission technologies for planning and real-time control. We believe it is essential that the proposed £3.8m reduction in EBS spend is re-instated to allow us to deliver real customer benefits at the earliest opportunity.

Wokingham Smart Workplace sharing

Proven concept for more efficient use of property space which drives opex efficiencies needs to be funded

33 As the size of our workforce increases to meet the operational challenges of the next decade we aim to increase the utilisation of our existing office space and rationalise where possible thus avoiding taking any new space. To this end we ran a successful innovative pilot scheme in our Warwick office for our smart work scheme. This provides a new, modern and flexible work environment that supports collaboration, improves employee productivity and reduces cost per person significantly. Space is divided into quiet work areas and formal and informal meeting areas and with no personal allocation of desks we reduce the amount of space per person from ~100 sq ft (the current industry benchmark) to 50 - 60 sq ft.

34 The Smart Workspace concept provides an increase in capacity in the order of 20% to 30% with no significant increases in operational costs. In addition, there are a number of environmental benefits. We have reduced energy demand by 16% in the pilot floor compared to our more traditional work areas and we have reused or recycled 94% of materials generated by the latest refurbishment. We have achieved Ska[1] accreditation for the latest roll out of the Smart Workspace concept which is an environmental labelling method designed to rate and compare the environmental performance of fit out projects for office buildings in the UK.

35 To date at Warwick we have converted six floor plates into smart workspaces. When the remaining five floor plates are completed the occupancy of Warwick will have increased from 1825 to 2433 people with a capability to increase further to 2800. The cost to complete the Warwick scheme is fully sanctioned. The scheme to increase capacity at Wokingham from 574 to 699 was sanctioned in September. The increase in capacity delivered at existing cost is equivalent to operating expenditure in the order of £0.6m per annum at an additional location.

[1] Launched by RICS, Ska Rating is an environmental assessment tool for sustainable office conversions

36 Ofgem reduced funding for this scheme pending further research to demonstrate the benefits. These have already been effectively demonstrated so there is no requirement for further research into the concept in our Wokingham office as suggested by PPA. With the benefits that arise from the investment the full [text deleted] should be allowed on an ex ante basis.

INVP 2476 Improved Modelling Transmission Analysis

Network analysis improvements which will minimise balancing costs should be funded

37 Transmission Analysis is carried out from seven years ahead right through to real time and post event. It is used to help design and run the network securely and economically. Existing processes are manually intensive and systems have limited capabilities for optimising or modelling dynamic equipment or demand side services. This means both systems and processes have limited capacity to adequately model the more volatile operating environment that is emerging as a result of the increasing intermittent generation.

38 We have identified an investment programme for RIIO-T1 to deliver the required improvements to Transmission analysis capabilities and to maintain the required IT service levels. This Transmission Analysis Roadmap (TARmap) programme includes this investment and the next.

39 PPA has proposed to defer INVP 2476 Improved Modelling Transmission Analysis by one year, which amounts to £1.9m reduction in allowances. This investment is integral for providing accurate planning and analysis capabilities. The key business driver for this investment line is having the capability to create accurate outage and network constraint plans to be able to facilitate the customer connections and maintain our obligations for system operation. This investment is planned to provide the ability to study outage and configuration plans with more granularity by having the tools to model the increased number of study points together with integrated scenario based evaluations.

40 The delivery of this investment is therefore critically interlinked with delivery of our capabilities. It will:

(a) enhance our transmission outage and planning systems

(b) create a probabilistic system security risk assessments

(c) provide optimisation advice on network asset settings

(d) integrate the planning functions with the energy balancing and forecasting operations.

41 The outcome from this investment will provide the benefit of automating repetitive tasks to reduce some of the non engineering burden and human errors. The major customer benefit is for us to have the confidence to create configurations for operating the network closer to the operational limits and thus providing significant savings in constraint costs. A deferral by the proposed one year of this investment will mean the delay in developing our capability ahead of time to ensure we can manage the increasing challenges we will face from wind generation coupled with greater interconnection, Demand Side Response (DSR) and smart grids. This delay will result in running the transmission network more conservatively with increased costs for wind curtailment and as a result reduction in the perceived cost savings we have modelled within our submitted business plan.

42 Currently, approximately 50% of a planner's time is required to set up the model to study a particular time period. One of the main reasons for this is the underlying data to set up the model is taken from multiple legacy systems. This investment will ensure that we have a more integrated data model for analysis alleviating the time taken to set-up the models and provide the capability to run a significantly greater volume of scenarios.

43 We have also stated that we will require funding in this area in 2020/21. New network modelling and simulation tools will be necessary to understand and predict the future impact on network performance and the proliferation of low carbon networks and the growth in electric vehicles and embedded generation. This investment is to proactively manage and plan for these changes in our operational environment at the back end of RIIO-T1 and at the start of RIIO-T2, allowing us to undertake advanced analysis factoring in greater amounts of renewable and embedded generation and increasing network information exchange with Europe.

INVP 1421 OLTA Hardware Refresh

Investment required to maintain critical network analysis system should be allowed, else system will be in place for over eight years

44 The Initial Proposals disallow all expenditure for 2015/16 and 2018 to 2020 for our OLTA Hardware Refresh scheme which amounts to a reduction in allowances of £3.3m.

45 The OLTA hardware upgrade investment in 2015/16 is to support the transmission analysis capability enhancements, particularly the increase in data flows arising from demand side response services and SMART network initiatives from the DNO's. This investment ensures that incremental upgrades to hardware and firmware are in place to maintain performance and mitigate any adverse impact from increased information exchanges with generators, suppliers, DNO's and Europe.

46 Investment from 2018 to 2020 is for a full OLTA hardware refresh. Without this investment in the period the hardware and firmware will be at least eight years old by the start of the RIIO-T2 period, in excess of benchmarks in this area. This will give rise to availability and performance problems and increase opex as the system will be outside vendor's supportable levels for one of our critical systems.

47 We anticipate that with increased data and information exchanges, maintaining performance will be critical. We will be required to enhance the hardware capabilities to provide more powerful assets to manage the increased data and processing requirements that will be needed. This investment will ensure that we migrate our functionality onto the latest technology platform and ensure that this hardware supports the enhanced capabilities.

48 Separation of the replacement of hardware from the application software upgrades within the TARmap programme, will result in the inefficient delivery of component parts – increasing overall costs - and sub optimal use of the upgrades to the application components of the programme of work.

INVP 1212 IEMS Future Upgrade

Develop lead time for refreshing critical system requires work towards the end of the RIIO-T1 period

49 PPA have deferred INVP 1212 IEMS Future Upgrade allowance from 2019 to 2021 as this immediately follows on from a replacement, stripping £7.3m out of the allowances.

50 The IEMS is our most operationally critical IT system which underpins our capability of operational control. This system covers both the NETSO and the TO roles for monitoring,

control, data provision and management of the work-flow for issuing of safety permits to enable maintenance work on the transmission network.

51 We have proposed funding from 2019 to 2021 to directly follow on from the full replacement of the IEMS system. Our IS policy is geared towards an asset refresh of CNI systems every five years. Delay of this investment will increase operational risks in acceptable performance and potential system failures. Previous upgrades of this system have taken typically up to five years from initial start-up to full commissioning into operation meaning that there is a considerable development lead time.

52 We expect that requirements for modifications on the IEMS to be more prevalent with the introduction of changes such as electric vehicles, increased impact of smarter networks and DSR services, offshore grids and the level of European interconnection. With these initiatives impacting our operations at different times, we are proposing to move away from the standard five year project delivery to enhance our capability and IT assets to a more agile, modular based approach. This approach of making annual investments to provide the required enhancements will ensure that we are able to implement changes more rapidly to meet the needs of our customers and the external environment.

Infrastructure for business systems

Higher allocation of costs due to increased users should be reflected in allowance for infrastructure expenditure

53 Ofgem have proposed reducing ESO expenditure on Infrastructure for business systems because the expenditure is higher than during the TPCR4 period. Our overall spend in this area in the UK is planned to reduce to an average of £6.5m per annum during the RIIO-T1 period compared to an average of £9.6m in the TPCR4 period. It is the allocation of costs to ESO that has increased due to a change in our infrastructure allocation driver. This driver uses the number and complexity of servers used by the applications owned by each business area to determine the share of costs for each form of control. Through IS Transformation more granular information about applications and their associated infrastructure is becoming available which has led to a greater proportion of these costs being allocated to ESO. The increase in capex costs for ESO in this area is therefore a better reflection of the costs applicable for ESO.

54 These investments are required to support the commodity IT systems such as e-mail and desktop applications and the associated hardware and infrastructure such as servers, storage, firewalls and desktop PC's or laptops. These infrastructure items may not be critical individually but are key enablers for all of our business capabilities. 94% of investments in this area relate to maintaining and refreshing our existing capability rather than further developments.

55 In general, if we do not invest in this area our hardware will become less dependable. As components age they become less reliable increasing the likelihood of interruption to our operations. As system performance reduces or as a result of actual failure. As the physical assets age it becomes harder to source replacement components, potentially leading to lengthy outages. A further factor is that support costs will increase if we do not invest, leading to higher opex.

56 As described in the 'Information Services Strategy' annex of our March 2012 submission, an IT system is composed of a number of interacting components. Changes to any one may lead to a requirement to change others. By investing in the underlying infrastructure, we ensure business driven changes to applications can be implemented efficiently.

INVP 2478 Smart Demand Side Data Interface

Acceleration of demand side response uptake requires research and future investment to minimise future balancing costs

57 PPA reduced INVP 2478 Smart Demand Side Data Interface by £7.2 million. Within the modelling that we undertook on uncertainty (included within Appendix A of our March submission) we illustrated that this investment could move dependent on the rate of the uptake of Demand Side Response (DSR) and Smart network services. Since our submission the momentum behind these technologies has increased and we therefore think this should be funded on an ex ante basis.

58 Smarter distribution networks will allow network companies to have more control over power flows and act as enablers for DSR. We anticipate that SMART networks and demand side services will play an increasingly important role in system balancing. There has already been considerable work in this area to promote development and remove barriers to smarter networks notably by DECC in partnership with Ofgem and the Smart Grid Forum. We are already seeing the roll out of smart meters and a number of SMART grid solutions being trialled by utilities. Our current market view is that 85% of commercial premises and households will have smart meter installations by 2017.

59 We are already utilising load shifting for commercial and industrial entities commercial contracts. There is increasing likelihood that SMART grid solutions and DSR will impact the management of the electricity network earlier than previously expected. In reality, this means we need to enhance our capability to manage these changes and the greater demand volatility that will prevail sooner than the planned timescales that we submitted in March. In addition, we will need to make this application scalable so as to be flexible to cope with innovative new DSR opportunities.

60 SMART grid solutions will change the demand profile and how we can actively forecast the shift in demand patterns. This will become more central to decision making since the future scenarios are expected to be very different to current trends. This investment will support predictive tools which will be used in the planning stage.

61 This investment actively manages the increase in data arising from SMART demand side services ahead of time to ensure proactive analysis and actions can be taken to preserve system security and minimise balancing costs. This information will continually improve our knowledge of how SMART solutions are implemented and form an important information base for our forecasting and planning functions with a positive impact on the amount of operating margins we require.

62 The current indication from DECC (Electricity System: Assessment of Future Challenges Summary, August 2012) and their work with Imperial college and NERA Economic consulting is that DSR will play an important role in system balancing. We believe that funding for this investment will reflect the importance that DECC and the market has placed on SMART networks and ensure that we can implement changes to manage the impact of SMART network developments on the transmission network and allow full commercialisation of any potential DSR opportunities. This supports the report conclusions for ensuring market arrangements are fit for purpose and supporting the development of key balancing technologies and promoting investment in smarter network technologies.

Data Centres (GSO and ESO)

Tactical approach outlined in the Initial Proposals would deliver a short-term, inefficient response to asset health requirements

63 We have undertaken comprehensive optioneering, both utilising internal resource and by engaging external consultants. We continue to work closely with both the Department of Energy and Climate Change (DECC) and the Centre for the Protection of National Infrastructure (CPNI) to develop the most appropriate strategy to protect our CNI systems from increasing security threat levels and the implications of ageing support infrastructure, the failure of which would have material implications for the operation of our gas and electricity networks. Development of the requirements and design of the final solution are well underway, however we will not have tender responses to assess the efficient cost of delivering this scope before Final Proposals.

64 Construction of new data centres is not part of our core regulated business, and it would therefore be inappropriate to incentivise us on scope of necessary works especially given this scope is being developed with the guidance and input from CPNI. We therefore agree that an uncertainty mechanism should be developed to set a target for only those works absolutely necessary to protect end consumers from the impact of failure of our most important systems, and that this should be done when efficient costs are understood. As construction is expected to be complete by the end of 2014, however, the reopener windows (the first of which is 2016) are too late to provide timely funding, and demobilisation of the current work to await the reopener window would drive total costs up, introducing inefficiency and exposing end consumers to an increased risk of failure of the CNI systems for longer than is necessary.

65 Given the timing of the reopener window, we propose that the reopener window explicitly considers historical costs incurred in the delivery of the project to that date and includes a materiality threshold that is proportionate to the likely costs.

66 We note that, if we were to only complete the tactical investments funded through Initial Proposals, this would deliver an inefficient, higher risk and short term solution, which would not deliver value for money. Refurbishment would have to be conducted in a live environment, risking CNI system outages whilst enhancements to cooling and power supplies are completed however this would still retain some existing issues. Security concerns cannot be mitigated, and the level of funding suggested would be insufficient to migrate systems and consolidate the data centre estate.

Gas SO capex

67 The investments that have not been funded are summarised below with indications of the potential implications.

Capability enhancements

Network Real Time Analysis and Optimisation (£3.3m, 2016 – 2019)

68 As we move through the RIIO-T1 period supply and demand will become more unpredictable and variable within day driven by, among other things, opportunities for price sensitive supply and increasingly intermittent operation of CCGT. This will require us, if we want to ensure the capability of the network is optimised at all times to benefit customers, to reconfigure the network and redefine critical parameters much more frequently than we do now, taking into account a much wider set of variables and potential scenarios.

69 This investments will introduce a real time optimisation system/algorithm into the control room to provide real time support to the processes associated with real time operational decision making on the network (decisions to bring on / take off compressors, re-switch network, amend pressure profile, redistribute line-pack and use commercial tools), within day, to maximise operational capability to allow customers increased flexibility to manage their flows – bring on gas power stations due to wind intermittency, reaction to UK/EU price signals and unplanned events.

70 Without this investment, we will place continual reliance on a combination of periodic analysis carried out some time before the event and operator experience/knowledge for optimisation decisions. If the predicted levels of volatility occur then this would lead to restrictions in the amount of flexibility customers can utilise as National Grid would need to take a conservative approach to operation to ensure safety with very limited within day real time reconfiguration available.

Intraday Volatility Management Tools (£6.3m, 2018 -2021)

71 Increasing within day flow variations caused by reaction to wind intermittency, pricing signals etc are expected to lead to changes in the commercial regime in the UK as products and tools are developed to allow these flows to be managed effectively. To allow these products and tools to be used effectively a range of operational tools will be required.

72 Without this investment the system operator would not be able to make effective use of new tools and products that are put in place leading to cost risk for customers and limited flexibility (and potential non-compliance with contractual obligations).

GNCC Customer Communications Automation (£2.9m, 2017 – 2018)

73 The two way transfer of operational information between National Grid and customers is currently carried out via a combination of faxing and limited electronic communications via the EDSS system. Neither of these processes / systems are supportive of the increasing frequency and changing content of data transfers that will be required to operate through the RIIO period

74 This investment will allow operational communications between NG and customers to be carried out electronically for flow notifications (and NG responses) as well as a range of other key operational data. This will replace limited current data transfer functionality and will eradicate the need for the considerable level of faxing of information that currently

exists (approximately 300 faxes per day/9000 faxes per month) and which we would expect to grow as operational volatility increases.

75 Without this investment the growing levels of data and frequency of communications with customers that will be required with increasingly dynamic operations cannot be accommodated effectively or would require more manual processes creating opex challenges and increasing human error risk. Customers have also stated that they want to see the removal of faxes as a primary communication methodology.

Other funding

76 Other funding which has not been allowed is associated with enhancements to:

(a) further develop demand and supply forecasting capability (£1m, 2020 – 2021), reflecting the expectation that supply and demand drivers will be so different by the end of the decade that the capability delivered early in the RIIO period will need to be significantly upgraded

(b) incrementally develop network analysis and modelling (£1m, 2016)

(c) deliver control room infrastructure changes for gone green (£1.8m, 2016 – 2021) associated with moving to a two hot control room model due to operational volatility, rather than a single live control room with cold standby that is the current model

Asset health investments

77 As described in the Asset Health section of the question 13 response to the 'Cost assessment and uncertainty Supporting Document' in our main IP response, a number of investments in the latter half of the business plan period have been deferred or removed in Initial Proposals. This impacts the investments described below:

(a) iGMS future refreshes: Initial Proposals appear to include PPA Energy's proposal to defer a number of investments by 2 years (iGMS Business Applications Refresh (INVP 3197), iGMS Enterprise Bus Refresh (INVP 3144), iGMS SCADA Refresh (INVP 3142), iGMS Data Management System Refresh (INVP 3143)). This is justified by PPA as they "appear to be commencing sooner than the five year refresh policy". PPA Energy's assessment is incorrect, as each of these investments lines delivers a system refresh 5 years after the completion of the earlier replacement. This can mean that initial spend may be required 4 or even 3 years after the completion of the previous project as some of these projects will take more than 1 year to deliver.

(b) Ofgem's initial proposals also defer asset refreshes for a number of systems which support GNCC operation (Network Simulation Asset Refresh (INVP 3115), GNCC Control room application suite replacement (INVP 0741), GNCC Control room application suite replacement (INVP 0741), GNCC Operational support infrastructure (INVP 1265), GNCC control telephony replacement (INVP 0538) and GNCC Control room infrastructure replacement (INVP 0217)). These each have similar impacts to those described above for the iGMS investment.

(c) iGMS Support Infrastructure Refresh (INVP 3140): Ofgem propose to reduce allowances by 50% in this area. As this level of funding will only allow us to refresh 50% of the infrastructure used to support the Production environments, we are concerned that the remaining 50% will incur premium hardware support costs (increasing opex) and constrain the level of regulatory or market-driven change we can implement when they fail.

78 Extending the operational life of the system will have a number of consequences:

(e) Increased risk of failure / reduced reliability, which may be partially mitigated by enhanced support arrangements from vendors where available.

(f) Increased support costs where additional vendor contracts are required to extend their support beyond their normal contractual terms. Our latest extended support contract with Oracle to cover National Grid's CNI systems which are running versions of their software outside of the vendor's normal contract represents a 35% increase in Oracle supports costs for iGMS. Assuming this is typical of future vendor extended support contracts, when applied to the overall iGMS running costs this could give an increased cost of over [text deleted] per annum.

(g) Increase in subsequent upgrade costs, which can be illustrated by recent experience of software upgrades. Oracle database and application server software, for example, cannot be upgraded from version 9 directly to version 11; the system must be upgraded incrementally. We have experienced the same issues upgrading our BMC Control-M job scheduling systems. These increase the costs of subsequent upgrades. Our experience from similar projects suggest that these costs could increase by 30% to 50%; when applied to the [text deleted] combined total of these investment this could give and increase in cost of [text deleted] to [text deleted].

EU regulatory requirements

79 Our latest view on the delivery requirements of the EU regulations and codes that are currently in development or delivery is:

(a) Constraint Management Principles (CMP) (Firm Use It or Lose it, Long term Use it or lose it, over-subscription and buyback, surrender of contracted capacity), which becomes an obligation in October 2013 will, for initial compliance, require developments to our MIPI system to meet new transparency obligations in the UK, as well as the development of significant new data transfer capability to the envisaged European Gas Transparency Platform. It is currently envisaged that the new CMP processes can be managed without system developments at initial go live due to the limited changes that they bring at this time, but will require significant systematisation in parallel with the implementation of Capacity Allocation Methodology (CAM) due to the interactions between the two code areas.

(b) The delivery of CAM (assumed 2015/16, and covering new and revised auction products, new methods of sale, release of Bundled capacity products, and utilisation of a common EU platform for capacity) will require developments on all of our major systems. A range of developments to support the new capacity release arrangements, constraint management (effectively a second delivery for CMP) and new systems developments to support obligated interfaces and information sharing with associated TSOs (across 3 interconnectors) and the obligated common capacity release platform. In addition CAM introduces the concept of a common gas day to GB which will require major system changes and a change to shipper, Delivery Facility Operator, upstream and Distribution Network Operator systems and equipment.

(c) The Balancing, interoperability and tariff codes are all at earlier stages of development but will almost certainly require implementation prior to the mid–period review and mandate significant process and system change (e.g. new nomination processes, within day obligations, and defined system format and protocols).

(d) REMIT (Wholesale Energy Market Integrity and Transparency) requirements are currently going through consultation but based on the latest Agency for Cooperation of Energy Regulators (ACER), documentation we will need to implement significant changes to processes and systems to meet obligations around reporting Wholesale Market Transactions, insider information, and disaggregated transparency data that will require us to upgrade systems to both capture all of the information required and provide it to the central ACER database as well as elements of it to the market via new website functionality. With National Grid Gas trading and contract processes amounting to hundreds of millions of pounds per year, across thousands of transactions, covering shrinkage, balancing, capacity, nominations, Operating Margins and various other arrangements the potential systems developments are extremely significant and, depending upon the solution proposed by ACER, could require us to fundamentally redesign some processes and systems to achieve compliance.

SO Opex allowances

Introduction

80 This section reviews the allowances that PPA and Ofgem have allowed for opex, both for direct and business support opex. Our response covers both gas and electricity allowances.

81 The single largest concern that we have about the allowances that have been presented is that in all categories (apart from ESO market facilitation) justification for reductions is based on the corresponding capex reductions for each network. We agree that there is a link, in many cases, but this methodology fundamentally simplifies the relationship between capex and opex, assuming that there is perfect linearity between the two. In addition, the assessment does not take into account that capex reductions are mostly at the back end of the plan. As they currently stand, opex reductions are phased proportionately across all years of the RIIO-T1 period. This methodology is therefore incorrect. This is explored in greater detail within each of the separate opex categories.

82 When these reductions are phased across each year the net effect is that allowances in 2013/14 are significantly below those that were granted in the rollover period despite the volume of SO related work increasing over this period. Not undertaking this extra work – which the initial proposals incentivise us to do – would detrimentally impact on our ability to manage our transmission systems as safely and reliably as customers and output measures require, as well as increasing the overall operational costs. These reductions are shown below.

Form of control	2012/13	2013/14
ESO	£65.4m	£62.7m
GSO	£34.9m	£30.6m

83 Reductions in ESO allowances are on top of the fact that between the two years a further £4.3m of costs have been transferred from ETO for Optel charges and moved to the ESO from of control. Greater details of this are given in the business support section. It is worth noting that as the assessment for opex costs is tied to the reductions in capex, any uncertainty mechanisms that are developed should be based on totex .

Direct Opex

Market Facilitation

Market Facilitation allowance reductions	
ESO	£15.7m
GSO	£13.8m

Market facilitation has been reduced to 2010/11 expenditure levels based on analysis errors and despite the growing influence of European energy policy

84 Market facilitation activities included within this area represent a key role that we undertake, helping to optimise the efficient management of the industry frameworks, providing connections to customers and delivering the services that they require. The daily activities are broad and include extensive information provision, individual customer relationship management and policy development at both a GB and European level.

85 Ofgem's current proposed level of allowances in this area are inappropriately low. The allowances that have been set are at a level that falls significantly below what we are currently spending on market facilitation, reducing us to expenditure levels in 2010/11. This is despite the growing market facilitation workload during the RIIO-T1 period with European policy being a key driver of the increase. The intention within the Initial Proposals to reduce expenditure within this area seems to contradict with Ofgem's view that we should be undertaking an active role in Europe. Whilst this just mentions it is fair to assume that this view is mirrored for our GSO role.

"As part of the annual monitoring of NGET's performance against its other outputs we will want to understand that it has contributed to the ongoing European regulatory developments and played its full part in this area[2]"

86 To provide further evidence of the requirement for sufficient ex ante funding, for this type of work, we have submitted a stand alone supplementary information document focusing on market facilitation.

Engineering support

Engineering support allowance reductions	
ESO	£20.2m
GSO	£2.7m

Errors in calculations for opex allowances incorrectly assume that these costs are linear to capex resulting in limited funding for long term approach to filling specialist resource shortages

87 The increase in engineering support costs that can be seen during the RIIO-T1 period can be explained by two principal drivers:

(a) Increase in the volume of trainees that will be recruited into our SO functions

(b) Increase in the volume of staff to support data management activities

Trainees

88 As documented within our March submission there are varying upward pressures that are driving the complexity of future system operation within the RIIO-T1 period both for the GSO and ESO. In order to facilitate this volume of work we are actively recruiting. As outlined within the workforce renewal and growth annex that we provided to Ofgem as part

[2] RIIO-T1 Initial Proposals – Outputs, incentives and innovation supporting document

of our March submission, we undertake a hybrid approach to our recruitment which relies on recruiting experienced hires but also training new recruits. We have several structured training programmes such as the graduate development programme and the foundation engineering scheme. These schemes are vital to support the long term development of new staff that will have the skills to support the increased workload of the RIIO-T1 period.

89 Due to the lead time to train these individuals there is a step change in headcount between 2010/11 and 2011/12. For ESO this amounts to an increase of 38 FTEs from an initial headcount of 77 FTEs for engineering support. Of these resources, 32 FTEs are for our Network Operations directorate, where half of them will be trained up to join our Transmission Requirements team which undertake 12 week to day ahead system planning. The remaining 16 staff are being trained up to join our control room shift teams to manage the growing real time system complexity or to join the operational issues team that is there to provide policy/advice into the control room post event assessment of operational issues. These increases also include the dedicated offline training resource that are required to manage these programmes and transfer their in depth business knowledge. The remaining 6 resources are graduates that have joined our Commercial directorate.

90 Over the same time period GSO headcount, for engineering support, increases by six to reach a total of 14, which is the extent of the headcount increase over the full RIIO period. Three of these resources are graduates that have joined our commercial directorate. The remaining resources have joined Gas operations within our strategy team where they will deliver offline support providing structure to the challenges facing our real time operations staff.

91 The cost associated with these new recruits then continues on an enduring basis for the remainder of the RIIO-T1 period as they support the growth requirements of the departments they have been recruited into. The increase in costs is therefore related to the increases in operational workload rather than our proposed increase in SO capex expenditure as assumed by PPA.

Data Management

92 The second driver of increased costs in engineering support, which relates only to ESO, is the increase in costs required for data management. In total we are recruiting a further 11 FTEs within this category of spend. The recruitment of these FTEs is staggered between 2012/13 and 2015/16, which brings the total number of staff in engineering support to a peak of 133 before dropping away in total to 126 staff.

93 Our data management requirements are increasing over the period due to the implementation of new IT systems, modern communications protocols and TO controllable assets combined with an increase in the number of planned new connections on the system. The specialist skills required for these roles will manage data from an increasing volume of Phasor Management Units (PMUs), series compensation units and new IT tools. They will be required to manage the data from these systems and turn it into useful information that can be used by the ENCC to maintain system reliability.

94 The biggest stand alone driver of increasing headcount for data management is related to the upgrade of communications systems on the GB network peaking in 2015/16. Manufacturers of Substation Control Systems have notified us that they will no longer supply equipment using the GI74 communication protocol, which was developed in the 1970s to send power system data to the control room. Modern industry-standard protocols deliver significantly enhanced information which will be essential to respond rapidly to network incidents, but the greater volume of data (typically three times that delivered under GI74) will increase the data management task. Within the Initial Proposals Ofgem

have allowed funding for this within our Non load related Protection and Control capex investments. Therefore disallowed opex expenditure in this area to replace GI74 is inconsistent with the corresponding capex provisions.

95 As this workload represents the majority of the data management resource increase it is inappropriate to reduce engineering support opex in line with SO capex expenditure. Without the corresponding opex to support this essential TO capex investment and the broader requirement for data management resources, then system safety and reliability as well as well as the optimisation of the efficient balancing of the network will be jeopardised.

IS Business Resources

IS Business Resources allowance reductions	
ESO	£2.3m
GSO	£1.1m

Our resources for IS delivery are reduced despite PPA stating they thought we did not have enough

96 Funding on IS business resources has been reduced in line with the proposed reductions in SO capex allowances. These resources are there to lead the development of the IS schemes that we require to manage the system of the future and are vital in creating the right solutions to the challenges we face. Within their report Ofgem's consultants recognised the need for IS business resources and went as far as to highlight that there was a risk that we did not have enough resources to deliver the projects. We are therefore confused as to the rationale for the cut in these resources when it was believed by PPA that we did not have enough individuals in our plan to start with.

Real time operations

Real time operations allowance reductions	
GSO	£12m

Errors in calculations for opex allowances incorrectly assume that these costs are linear to capex, whereas requirement would be more with disallowed expenditure

97 Again PPA have reduced the level of expenditure for real time operations in line with the proposed reductions in capex. It is incorrect to assume that staff increases relating to real-time operations of the NTS (such as control engineers) contribute directly to the development of the required investments, and therefore it is incorrect to pro-rate these resource increases in line with the proposed reduction to the SO capex plans. The proposed cuts have the net effect of initially reducing the allowances below those received in rollover despite the increasing workload that we face in managing a more complex GSO environment.

98 The key workload driver for increasing headcount in real time operations is to respond to challenges presented by increasing variability in gas supply and demand patterns that we

anticipate over the next ten years. We expect to see fundamental changes to the way gas is supplied to, and taken from, the NTS which is primarily driven by the decline of UKCS gas supplies, which are being replaced with a combination of LNG, European imports and increased storage capability, and later in the decade the decarbonisation of the electricity supply chain. As a result we are necessarily increasing the resource levels within the Gas National Control Centre (GNCC) which are set to increase from the 42 FTE operating in the control room environment in 2011/12 to 60 by the end of the RIIO-T1 period. This increase is staggered across the RIIO-T1 period and discussed in further detail below.

99 Over the next two years we are planning to increase headcount by six resources (one per shift team) to ensure appropriate resources are in place to manage physical system operations, system optimisation, and to provide increased resilience in the face of rapidly rising workload. The current GNCC shift structure has been in place since 2004 and during this period the size and complexity of the NTS has increased, as have the number of customer interfaces. Pressure, flow, line-pack and gas quality management has also increased significantly in complexity with the decline of the UKCS supplies, and the increase in diverse gas supplies entering the NTS. Efficiencies have been made through workload organisation and system optimisation but an increase in Operational engineers is now essential to ensure that GNCC continues to operate the system safely and efficiently.

100 Due to the age of the NTS maintenance workload activities have increased significantly in recent years which is also a factor driving increased workload volumes into GNCC. From planning and scheduling perspective, and to provide direct support to the Control Room, a resource will be recruited into Physical Operations during 2012/13 to manage these activities.

101 During 2015/16 a further shift position (six resources) is forecast to be introduced into the Control Room in line with anticipated increasing volatility of supply and demand on the NTS as described in more detail in our March submission document. This is from a combination of increased price responsive behaviour from LNG and storage sites (which have much greater ramp rate potential compared to beach supplies) and increasing intermittency on the electricity system as renewable generation sources connect. These resources will be focused on providing medium term strategies to drive optimum operating strategies to ensure that GNCC can effectively manage system risk and uncertainty in increasingly constrained and challenging conditions. These roles will also provide capacity to operate new modelling capabilities and decision support tools that will be introduced during the middle of the decade.

102 We have also identified a further six resources during 2018/19 to support the strategy desk in operating the business capability tools that are being developed as defined in the GSO Capex plan. This is driven by increased frequency and magnitude of significant balancing events, and increase in need for both operational and commercial actions, with volatility of supply and demand becoming normal operation. This headcount increase will also support overall control room resilience and will be initiated at the same time as a revised rota system and shift organisation.

103 Increasing the headcount within our real time operations area is part of our holistic strategy for the most economic provision of the capabilities that we require to operate in a more complex operational environment, balancing IT investments, FTE increases and changes to commercial arrangements. We therefore consider that the proposed reductions in allowances should not be related to GSO capex reductions.

Business Support Opex

Information Systems & Telecommunications

Information Systems and Telecommunications allowance reductions	
ESO	£61.6m
GSO	£21.7m

Errors in calculations for opex allowances incorrectly assume that these costs are linear to capex, disallowing more expenditure for IS support than was originally in the plan

104 Our IT and Telecoms costs for our SO functions are made up of three major components:

(a) Underlying IS costs – includes the costs of our outsource contracts, telecoms, IS application support and software licences and IS management

(b) CNI support costs – internal support staff costs plus contracts for support of CNI systems (iEMS, Balancing Mechanism and iGMS) and networks (Optel and Ulysses)

(c) IS investments – the change in support cost due to increases in the number and complexity of systems being supported

105 To illustrate the depth of the proposed cuts we have broken down this category of expenditure into its constituent parts and illustrated this in the following two graphs, one for ESO and one for GSO.

106 Underlying opex is represented by the green bars. These reduce across the RIIO-T1 period as the savings from our Transformation programme develop. Initial increases between 2010/11 and 2013/14 for ESO and GSO are driven by changes to allocations for Optel (reflecting network usage) and from Gas Distribution (reflecting more the granular data available to us as part of IS Transformation) respectively. The affect of these changes have been added to show the profile of costs on an equivalent basis as if they have been in place during 2010/11.

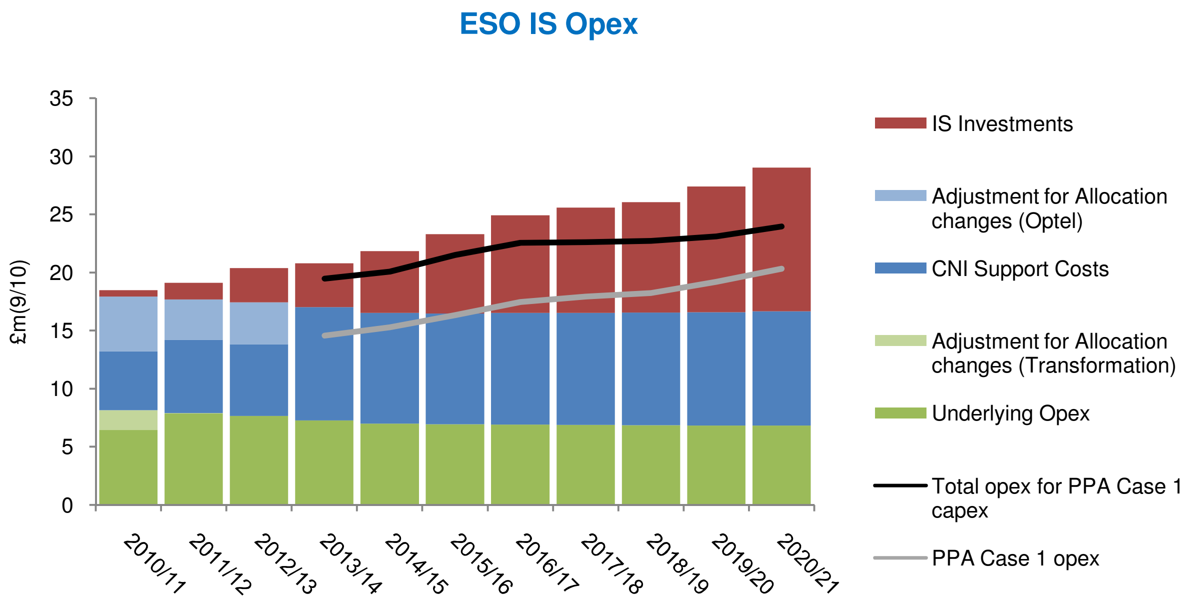
107 It is important to note that as the allowances currently stand Ofgem have not taken on board the allocation changes for Optel costs. The £4.3m reduction from TO has been accepted but the resulting increase in ESO costs has not been allowed in the Initial Proposals. This is despite there been no justification to suggest that these costs are inefficient or not required. Therefore from 2013/14 onwards our ESO allowances should be increased by this amount. Greater details in support of this allocation change were presented to Ofgem on page 56 of our Detailed plan – support costs annex in March.

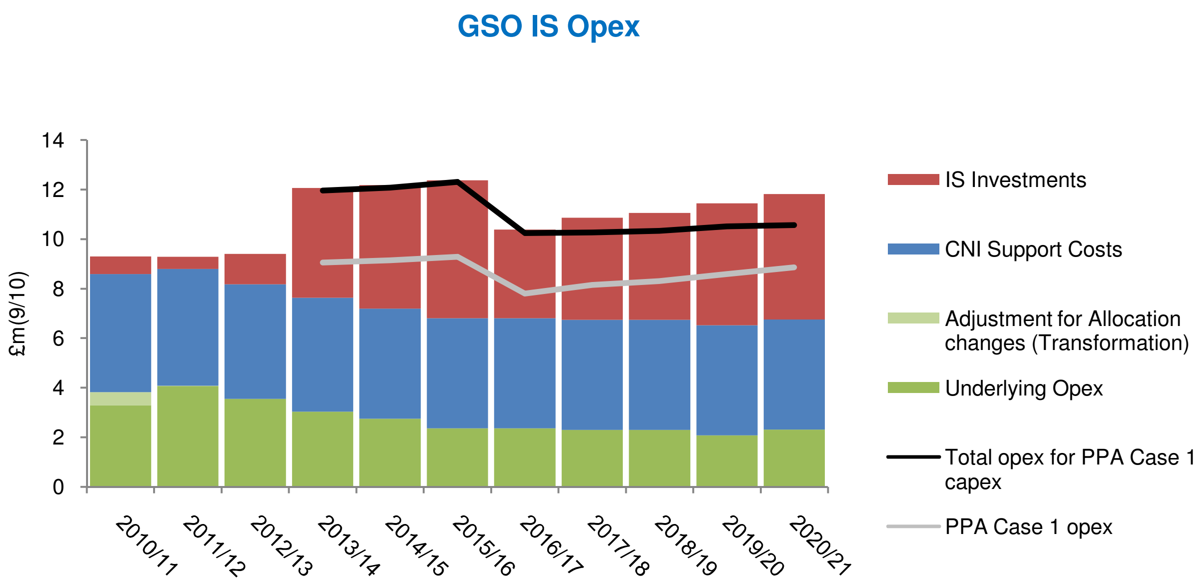
108 Our 2010/11 costs were benchmarked by Gartner against similar organisations and (non-CNI) costs have also been recently market tested as part of our IS Transformation programme. We therefore consider that they represent an efficient level of costs to support our current IT estate.

109 The second category of costs to support our CNI systems (illustrated by the blue bars) reflect their criticality in maintaining supplies of gas and electricity to consumers. To achieve this we monitor system performance on a 24/7 basis, maintain duplicate and geographically separate infrastructure and contract for application support with a 15 minute response time. All of this is increasingly essential in a less operationally predictable future to deliver against our reliability and safety output measures and to promote UK wide security of supply.

110 The red bars reflect the increased net cost due to investments between 2010/11 and the end of the RIIO-T1 period. The green and blue bars are not affected by investments (although if we did nothing at all these costs would increase).

111 Once these categories are summated we can then compare this against Ofgem's proposed IT and Telecoms opex allowances for ESO and GSO which is illustrated by the grey line within the graphs.





112 Again PPA's proposed opex reduction are based on a reduction in the number of FTEs proportional to the reduction in allowed capex (25% and 30% for GSO and ESO respectively). This methodology is flawed in two key ways:

(a) The cost associated with people working directly on IS projects will be charged to those projects (as capex) and therefore has been excluded from our opex plan

(b) Only 12%[3] (gross) of our IT and Telecoms costs is for FTE's, the remainder relates to software licences and support contracts

113 Support costs do change with the implementation of system changes, however this is not a linear impact and is cumulative – removing an investment from the latter years of our plan will only affect future support costs. To illustrate this we have re-run our support cost model (described in our IS Strategy Annex on pages 71 to 73) in line with PPA Energy's recommendations for SO capex. On this basis the reductions in opex for ESO would reduce from the currently proposed £61.6m to £21.8m and for GSO should reduce from £21.7m to £4.9m. This level is illustrated by the black line in the two graphs above.

114 For GSO, our costs increase temporarily between 2013/14 and 2015/16 by £2.35m per annum. This is due to stranded costs associated with infrastructure currently shared between Gemini and iGMS. These costs will be borne fully by iGMS from April 2014 once the Gemini re-platforming project is complete. However it is not possible to remove these costs until our iEP programme is completed and the infrastructure can be decommissioned. Overall (and as explained in our submission), iEP is the most economic way of managing the replacement of iGMS, and any attempt to decommission this equipment earlier would lead to higher overall totex.

115 In conclusion the assessment above shows that the proposed allowances are too penal and in the extreme do not even fund us for the support of the existing ESO IS portfolio. It would be more appropriate to reduce just the "IS investment" part of our costs (those in the red bars) in line with any capex reductions. The level of reductions currently included in Ofgem's initial proposals puts our ability to continue to deliver current levels of reliability at risk let alone meet the expected challenges ahead.

116 Finally any funding of future capex, through an uncertainty mechanism, should correspondingly include an uplift in opex allowances.

Property Management (Data centre reductions)

Property Management allowance reductions	
ESO	£12.8m
GSO	£12.8m

More expenditure than was in the plan has been removed for data centres and short term approach will require continuation of costs for site which was assumed to close under our proposal

[3] FTEs and agency staff make up on average 12% across the TPCR4 and RIIO-T1 periods of our gross IT and Telecomms costs in the UK before capitalisations and including both operational and non-operational costs. 15% of our non-operational IT and Telecomms costs relates to FTEs and agency staff. Pensions costs have not been included.

117 Reductions for data centre related opex should only be £8.75m for each form of control, compared to the £12.8m assumed in the Initial Proposals. Errors in analysis give rise to the difference.

118 Part of the expenditure included within the property management category relates to our data centre strategy. In their review PPA deducted £1.6m per annum for both ESO and GSO from the beginning of the RIIO-T1 period. This figure was incorrect as the actual value of opex costs related to data centres was £1.435m per annum as illustrated in our opex trace data tables 2.14a. This incremental opex cost only applied from 2014/15 onwards, not from 2013/14 as assumed in the Initial Proposals.

119 Within the Initial Proposals, Ofgem have only funded capex investments for delivering tactical investments (see Data Centre section above), with potential further mandated investments to be funded through an uncertainty mechanism. Opex costs associated with data centres will therefore be dependent on the final design of the appropriate enduring solution. As we specified in our Detailed Plan – support cost submission, the incremental opex costs from our proposed data centre strategy was circa £1.2m per annum for implementing 24/7 manning and circa £2m per annum for critical server cooling. These figures have been calculated at an overall National Grid level with 40% of costs allocated to ESO and GSO accordingly. Taking these into account then the reduction in opex costs from the property management should be as follows:

£m(9/10)	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	Total
ESO	£0m	£1.25m	£1.25m	£1.25m	£1.25m	£1.25m	£1.25m	£1.25m	£8.75m
GSO	£0m	£1.25m	£1.25m	£1.25m	£1.25m	£1.25m	£1.25m	£1.25m	£8.75m

SO Uncertainty Mechanisms

120 Within our submission we discussed the need for uncertainty mechanisms in relation to the uncertainty regarding GB and EU market change. In addition, we considered the merits of creating an SO uncertainty mechanism within our March RIIO-T1 submission based on uncertainty of cost drivers such as wind generation levels, recognising the uncertainty surrounding the requirement for investments at the latter half of our SO plans. From our analysis for the ESO, we calculated that the risk of over or under spend was broadly symmetrical. As a consequence we initially did not believe that it was appropriate to specify an uncertainty mechanism and only proposed mechanisms for market change.

121 The GB and EU uncertainty mechanisms are discussed in detail within the Supplementary information: market facilitation document so this is not repeated here. Instead we focus on the uncertainty in relation to capability developments in the latter half of the RIIO-T1 period.

122 Within the Initial Proposals Ofgem reviewed our capex plans and commented that:

"There are some instances where the forecasts have considerable uncertainty built into them and consequently into NGET's and NGGT's proposed baselines. Given the lack of justification and to protect the interests of consumers we consider that the Case 1 upper reduction scenario is appropriate"

123 As an eight-year price control, RIIO-T1 requires a different approach to a more traditional five-year control. Whilst we accept that a longer price control brings benefits in terms of incentivising the network company to made efficient decisions beyond the shorter five-year horizon, the longer period has inevitable consequences for the form of the control, including greater utilisation of uncertainty mechanisms.

124 As we move into a longer term price control there is inherently a greater level of uncertainty and risk that we face in terms of how we will overcome the future challenges of system operation. We were comfortable that this symmetrical risk was something that we were best placed to control and that minimising the number of uncertainty mechanisms was beneficial in reducing regulatory burden and increasing transparency. However, with the proposed reduction in funding for investments in the latter half of the plan, the risk is now asymmetric and in our view no longer best protects the interests of consumers as Ofgem state. This is because capability developments, if required, will minimise balancing and constraint costs and not having access to funding for these developments incentivises us to allow these costs to increase.

125 Without uncertainty mechanism(s) (one for ESO and one for GSO) that allows for funding of necessary investments to manage the challenges of an evolving system operation environment we will end up running our systems in a more conservative manner so as not to jeopardise system reliability and safety. This will not be in the best interests of consumers, contrary to Ofgem's statement, as we will be less able to reduce the forecast increase in external balancing and constraint management costs (which are fed through to the end consumers) and deliver the flexibility and innovation that our customers require.

126 We therefore believe that the interests of consumers are now best protected by the introduction of a specific funding mechanism for ESO and GSO that allows us to have access to incremental funding to invest in systems to meet future challenges. Indeed this view is mirrored by PPA, and should be reflected by Ofgem if they are to use PPA's case 1 scenario.

"It is therefore proposed that an uncertainty mechanism is introduced that provides for further allowances"

Uncertainty mechanism design

127 In setting an appropriate uncertainty mechanism we take guidance from Ofgem, as set out in their strategy document. One of the key principles for the use of uncertainty mechanisms is that they should only be used in instances in which they will deliver value for existing and future consumers, helping protect against windfall gains and losses.

128 As operator of both the gas and electricity transmission systems one of our key concerns is to have the appropriate capabilities to manage the systems in an efficient, safe and reliable way. Without this, either the risk of managing the system and delivering SO outputs will increase and / or the external balancing and constraint management costs borne by the industry will increase. To mitigate this we need to strike the right balance of investing in these capabilities so that they are available in a timely manner to help optimise system operation both from a risk and cost perspective. In designing the mechanism there needs to be enough lead time so that systems can be designed, developed and tested prior to implementation into the production environment. Previous experience has shown us that in deploying new systems the process can take anything from one to five years dependent on the scale and scope of the systems. Therefore the uncertainty mechanism(s) needs to be flexible enough so that they fund investments at the appropriate time.

Mid period review

129 Given our views on the requirement for a mechanism to reopen allowances for SO investments we are encouraged by recent conversations with Ofgem suggest that some of this risk can be covered by an uncertainty mechanism. However this is neither explicit in the Initial Proposals nor adequately defined for us to be comfortable with this approach. For SO costs, PPA recognised that the uncertainty is not around the outputs; rather it was whether external factors such as growth in wind generation, smart demand and gas system volatility occur at the rate we initially assumed within the plan. This uncertainty led PPA to conclude that you cannot set all allowances on an ex-ante basis eight years in advance in such a dynamic environment as the SO.

130 If the capability developments in our plan are not funded on an ex-ante basis – which is our preference – then funding for future SO investments should be triggered by changes to our operating environments, which rely on us justifying the requirements for the 'new' schemes, rather than a review of outputs. We propose that there should be a specific uncertainty mechanism that is assessed at the mid period review, when external driving factors will be much clearer, or that proposals in this area to cover such schemes within the mid-period review are made more explicit.

131 There are a number of further concerns that need to be addressed and clarified through the detailed design of such a mechanism:

(a) As there will be a single re-opener, in order to not detrimentally affect the timing of investing in required systems, the mechanism needs to be flexible enough to allow us to submit evidence of expenditure above the baseline allowances on a retrospective basis but also submit future forecast requirements for consideration

(b) As PPA have reduced our opex allowances on the back of reductions in capex due to a perceived positive linearity of these costs, any mechanism that adjusts for increasing capex requirements needs to also cover the associated opex

(c) The applicability of a materiality threshold, and how this would be calculated

132 In conclusion, having a suitable funding mechanism will deliver against Ofgem's principles around uncertainty mechanisms. It will protect consumers through minimising proposed SO investments and also protects them by allowing us to provide an evidence based case for future investments that will maintain the delivery of outputs whilst minimising increasing balancing and constraint management costs.

133 We have only covered the requirement for SO uncertainty mechanisms within this document. The GB and EU uncertainty mechanism is commented on in the market facilitation document.

Detailed review of PPA arguments

Introduction

134 This final chapter is a review of the arguments that were produced by PPA which have been used to underpin the allowances. Each section gives further evidence to support our view or provides justification for why the arguments are factually incorrect.

135 This chapter has been outlined in a way that mirrors the structure of PPA's document to help with cross referencing purposes, thus we have used the same titles for sections. Initially we look at the comments raised that have equal merit for both of our SO functions and then we focus on each SO function separately.

Electricity and Gas Joint Issues

IT Strategy

136 Ofgem in their Initial Proposals have repeated the concerns of their consultants about delivery risks associated with our IS suppliers. PPA's report raises the following concerns;

"There is a heavy dependency on external suppliers based on 5 year contracts and there is a risk that they may not renew."

"It is noted that the IT strategy is based on a 5 or 6 year replacement cycle that leads to almost continuous system development with attendant risks. This appears to be linked to five year outsource contracts with IBM and Wipro with no guarantee of renewal."

"IS Supplier side risks leading to withdrawal of their services due to business failure or loss of key support staff"

"There is a heavy dependency on external suppliers based on 5 year contracts and there is a risk that they may not renew."

"Another IT related concern is the heavy dependency on external suppliers based on five year contracts, and the risk that they may not renew"

137 Whilst we acknowledge there is a risk that external suppliers may not renew, this would be a feature of any supply or service arrangement in all areas of activity. In the material provided following the cost visit in May 2012 we have provided details of all of the measures taken to ensure that we have appointed Solution Delivery Centre (SDC) partners with the scale, solvency, track record and knowledge to support our demand over the plan period. Appendix D of our 'IS Strategy Annex, provides full details of; the rationale, approach and contracts which underpin our sourcing arrangements. These contracts are not all five year contracts and there is no linkage between our contract periods and our Asset Refresh Policy. They range from three years (with options for up to two years extension) to seven years (with an option of further two years). These terms have been set in recognition of potential technology change in the areas of each contract.

138 The Application Maintenance and Delivery contracts with IBM and Wipro are for five years plus option for two, one year extensions. In addition, in the appointment of CSC and Wipro as providers within our strategic partner group, we have demonstrated our ability to work with, retain and renew arrangements with our suppliers. We also provided details of contingency arrangements in our response to the question "It is understood that the Wipro

and IBM contracts are for 5 years. Question - what contingency plans are in place if they decide to discontinue?" at our May 2012 cost visit and follow up material.

139 As such, whilst acknowledging the risk, we have provided substantial evidence to demonstrate our track record and the mitigating measures we have taken, such that this concern should be considered inaccurate and should not be reflected in the assessment.

Programme implementation and staffing requirements

140 The comparison of the ratio of specialist support staff per £m of capex between the GSO and ESO cannot be made on a like for like basis and therefore the conclusions reached that we have insufficient resources to support the capital programme are factually inaccurate. As discussed within the SO cost visit on 3rd May, the source of the ESO headcount, used by PPA to create the graph, prior to 2011/12 could not be verified by ourselves or subsequently, when asked, by PPA. It could not therefore be ascertained whether the headcount was just for FTEs that book 100% of their time to the project or whether it also included the summation of staff that spend part of their time contributing to the projects. We do however know that the ratio of one FTE per £1m of capital spend applies historically when we look at a individual projects, where only full time specialist resources have been counted.

141 We can confirm that the data from 2011/12 onwards for ESO only includes headcount for individuals who work on the projects full time. This differs from the comparative figures for GSO where the headcount of FTE's includes the allocation of time from staff who spend a minority of their time working on the capital projects. So for example, to make a like for like comparison we would have to include staff, for ESO, that spend only 10 or 15% of their time working on capital projects. Furthermore, the ESO function has a dedicated testing team provided by one of our global IS partners which specialises in the full suite of testing services, that undertakes some of these functions for each individual scheme meaning that less resource is shown directly against the projects when compared to the GSO ratio.

142 Therefore it is inappropriate to use these considerations in influencing *"the thinking in scaling back the capital programme to a more manageable level"*. Indeed we are further confused with the rationale to cutting our IS business resources when our opex costs are reviewed, if indeed it is PPA's opinion that there is deliverability concerns due to lack of resources.

Risk and uncertainty

143 PPA state within their review of our submissions that *"the risks associated with the IT refresh policy are not discussed, nor how such risks are managed".* We are disappointed that PPA continue to take this view when we have provided detailed explanations to cover this criticism in previous correspondence.

144 There are two aspects to the "risk" associated with our IT asset refresh policy, the risk associated with operating the network on unsupported IT hardware, software of infrastructure and the implementation risk associated with delivering the change programme. The latter risk assessment (which we assume PPA are referring to here) is discussed in detail within our IS Strategy Annex, in paragraph C113 to C124 along with a case study in respect of the Energy Balancing System. The former was explained in detail in our response to RT1-Ph2-52 and TR1-Ph2-73.

Electricity Issues

Overall Approach and Options

145 Within this section PPA list three options for ESO developments over the RIIO-T1 period.

(a) Use more people but ‘the processing time for manual intervention would not be able to cope’

(b) Extrapolate the use of existing facilities increasing the volume as well as the depth of the task that could be carried out through greater automation’ but ‘this could be solving the wrong problem’

(c) Pursue an approach of enhancement to facilities to improve confidence, assess more scenarios and respond more quickly.

146 The way that these listed options were presented is misleading and does not capture the holistic options that we review when deciding on how best to meet the challenges that we face. The System Operator primary aims are to maintain reliability, deliver on our licence obligations, reduce overall costs of operating the transmission system and maintain safety.

147 As we enter the RIIO-T1 period we will respond to these challenges through developing processes and tools to attain and maintain the required capabilities to facilitate safe, reliable and efficient system operation.

148 At the highest level we look to balance expenditure between our SO and TO functions to come up with the optimum solution for our stakeholders. These include:

(a) Investment in physical assets

(b) Installation of smart technologies on the network such as generator intertrip systems

(c) Creation of commercial solutions

(d) Developing system operator capabilities to maximise the use of existing and newly installed Smart assets

149 At a more granular level, to deliver the enhanced SO capabilities needed for the challenges of operating the network in the RIIO-T1 period we could:

(a) Increase our resource capability by increasing the number of FTEs and invest in more training

(b) Develop further contractual solutions such as generator intertrips and ancillary services

(c) Propose changes to the existing commercial frameworks

(d) Make alterations to the processes we use

(e) Invest in IT system solutions

150 Indeed the list of options show that both opex and capex solutions can be optimised to deliver the capabilities that we require at minimum cost for the end consumer.

151 We have presented the System Operator plan to deliver business change ensuring that the right investments are made in resources and systems and that the business processes and commercial agreements are in place ahead of any anticipated impact to our operations.

152 The transmission system is managed by performing a number of actions and invoking services provided by the market. The actions and services are either taken:

(a) following pre-event analysis (often computer aided)

(b) following on-line and off-line analysis by automatic systems

(c) following real-time evaluation (based on monitoring information)

(d) eventually, following post-event investigation

153 Insufficient focus in a particular area would invariably imply a non-linear increase in costs in other areas. For example, if we had to keep our capex expenditure constant (i.e. no improvements on our systems to control the network) and we want to reduce the internal opex expenditure, this will likely mean a higher expenditure in the balancing actions as there will be fewer resources to assess the market. This is not the efficient solution for consumers. Instead, internal SO costs and external balancing costs need to be minimised as a whole.

154 We continue to also implement a large number of process changes to avoid increase in costs and avoid reduction in reliability. For example switching network cables to maintain system voltage overnight instead of buying reactive services from generators and use of smart re-switches in substations to avoid generation constraints. These present regular challenges to the operator and stretch the use of the system closer to its limits.

155 In summary, we have presented a well justified business plan for capital and operational expenditure to ensure the System Operator has the necessary capabilities to respond to today's and tomorrow's challenges, making sure they are delivered only when required for system security and operability. This plan looks to optimise across our SO and TO functions and also optimise internal and external costs for the benefit of the end consumer. This approach is forecast to generate cost savings on balancing services in the magnitude of £600m, far outweighing the internal costs to achieve this.

156 The proposed delay and reduction of some of the key investment projects proposed by Ofgem will compromise our ability to respond to some of the challenges we see today and tomorrow, with the cost savings on external balancing costs either being delayed or not achieved.

Major Concerns

Governance for business change

157 PPA stated in their report (Section 3.2 p25) that *"the programme will not focus on the most critical aspects".*

158 We recognise that it is more important than ever to deliver timely business solutions, just ahead of any significant impact. We have highlighted within our ESO business plan that for successful delivery, we will need the right mix of resources (and training), business process developments and commercial arrangements which are supported by IT solutions underpinned by innovation and continuous improvement.

159 Over the last 18 months, we have leveraged expertise from external consultants to realign our governance models with the creation of steering groups, planning and support functions. The objective of this reorganisation has been to ensure we focus on the right business changes and needs. The steering groups focus on medium to long term objectives with the planning and support functions geared towards short terms delivery activities.

160 These new structures give us a clear end to end view of the developments required and view on the interdependencies between changes. This enables us to set the correct priorities and ensures our resources have the flexibility to easily adapt to the needs of the external environment.

161 PPA suggested that our approach appears *"technology rather than business driven"* (section 3.2 p25) and that *"it appears that the process of project definition is not based on the development of business process definitions but rather these are developed later in the project"* (section 3.2.3, p28).

162 We have stated that our approach has moved away from standalone IT solutions to delivering programmes of business change. The different strategy groups within ESO identify the long term business capabilities that are required. The solutions delivered are a combination of business changes IT solutions, resource requirements and commercial agreements.

163 All IS investments are driven by a business case. The business case is scoped to provide the optimal solution for security of supply and perceived business benefits/efficiencies. Changes are continuously reviewed and prioritised regularly to ensure they remain in line with the business needs.

Drivers – Wind

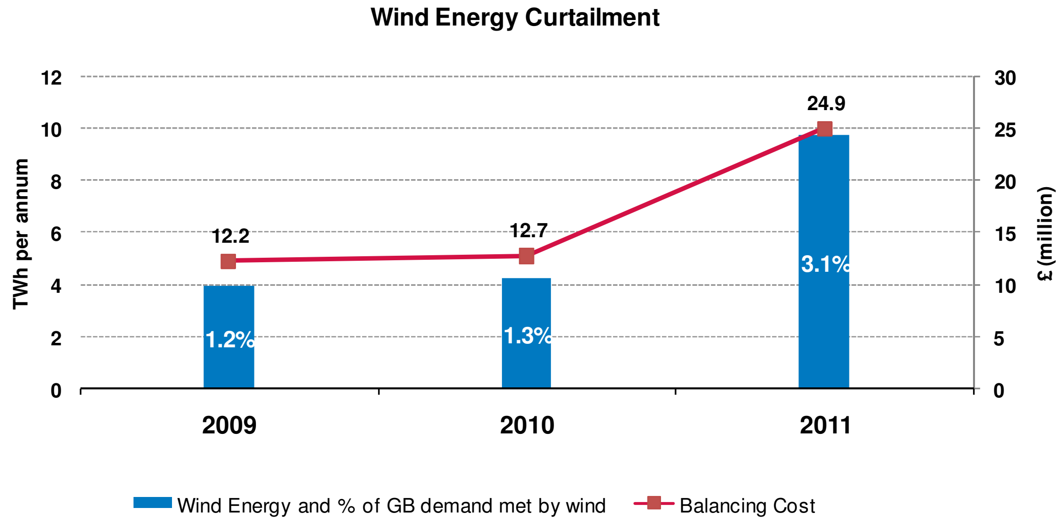
164 PPA reviewed the principal drivers for each of the proposed IT investments over the RIIO-T1 period. Out of the 88 investment lines the largest driver was for hardware refresh projects at 35% followed by increasing wind generation at 20%.This was the single largest external driver

165 It is important to reiterate that the majority of our investments provide solutions to respond to multiple drivers. For example, we are investing in automatic post fault actions (INVP 2475) not only to manage increasing wind generation but also to facilitate new intra network HVDC technologies and the implementation of increasing numbers of QBs on the network. Increase in wind generation is one of the principle drivers.

166 PPA have assumed 20.7% wind capacity penetration by 2020, which is the volumes stated within our slow progression scenario, instead of the gone green assumption of 25.3% This rationale was used as the main justification for reduction of our capex allowances. We are concerned with PPA using slow progression wind penetration estimates as the basis for their analysis. This view was echoed by some of our stakeholders at the most recent stakeholder engagement session held on the 4th of September. They questioned whether Ofgem's consultants believed that the UK environmental targets will be met, and highlighted a danger that – if they did not – the regulatory deal would not be sufficiently ambitious jeopardising the country's goals.

167 We have seen a progressive increase in the level of wind penetration over the last five years and we expect this trend to continue. There has been a number of occasions to date where the short-time and real-time operation of the system has been confronted with a large number of challenges due to, amongst other issues, the amount and volatility of wind output. Thus far, these occasions have been limited and have been managed at the

expense of balancing costs. However there is likely to be an upward trend in these events and associated costs as illustrated within the graph below.



168 Some of the capability enhancements included in our investment plan will provide the tools to monitor and react to these challenges in shorter timescales and reduce balancing costs. Earlier implementations of some of these tools will ensure we can provide the business benefits (i.e. savings in balancing costs) earlier. The big risk for our operation is that once the potential output of wind doubles or triples in the future, the impact to the security of supply will be unacceptable.

169 PPA argued in favour of providing allowances for delivery of certain investments, which would in their view provide the maximum benefits such as wind forecasting tools. Enhancement of our wind forecasting system alone will not deliver the required capability or tangible efficiencies. To ensure the system is more reliable and secure, enhancement of the full end-to-end process is required. We will be looking to develop tools to communicate with sites, monitor and control connectivity (SCADA), manage output (EBS), minimise variability (AGC) and analyse trends and past events (Data Historian). It is the combination and use of the wind forecasting data that generates the value of better forecasts, with benefits only being achieved through the development of the constituent parts.

Business process definition

170 PPA further commented on our business processes definitions by stating that *“existing documentation is very high level and only refers to processes and not data flows”* and that *“there has been limited progress in recording existing business processes in detail and apparently little for proposed developments”* (section 3.2.3, p29).

171 Business processes underpin the operation of the GB Transmission network. We have always recognised that to maintain quality standards and deliver on our licence obligations, documented business processes play a crucial role. There is a full suite of process maps and process documentation accredited to ISO9001:2008 that describe the processes currently in operation within the ESO. The Process Maps illustrate at all levels the information exchange and workflows between the different areas affecting the ESO.

172 Changes to the business processes can be triggered by a number of factors for example, a business change, external development or by new IT systems. For example, for the new EBS system, we have created a number of 'future' processes using the Aris software package to align the changes to our business goals.

173 It is the responsibility of the relevant business owner to ensure that all their processes are documented and updated regularly. These processes are audited internally and externally to maintain our ISO 9001:2008 certification and provide assurance that our management systems are robust.

174 Information on some of our current and future business processes has been shared with PPA following on from the cost visits. We therefore do not believe that there is merit in PPA's concerns surrounding our business processes.

Comparison with other utilities

175 International comparisons and benchmarking played an important role in the development of our investment plan.

176 Discussions with the Irish TSO, EirGrid, have provided us with useful learning points on some of the challenges that we will need to address over the next eight years. However, we expressed in our March submission that the *"Irish system had different market rules and is small in comparison"* which PPA have challenged as they were not clear why this would make a difference.

177 A similar argument to ours was stated by EirGrid in a report they published in 2007 which focussed on benchmarking islanded electricity systems *"Proposed System Operations Services', Payments & Charges in SEM"*[4]. The report says that the GB system is not comparable to Ireland as the GB network is ten times bigger and the market arrangements are much more complex. In essence, we think we can still learn from other TSO's experiences, but the solutions will have to be adapted for our system. We will continue to engage with other TSOs and learn from bespoke meetings and our participation in benchmarking activities such as ICTSO.

178 PPA suggested in section 3.2.5, p31 that one of the key developments proposed in the Irish DS3 programme is the development of a Wind Security Assessment Tool (WSAT) costing roughly €0.5m for wind security assessment which is able to accommodate 40% of wind penetration. This tool has been developed in addition to other significant investments on their transmission network. The EirGrid network has evolved over the past decade with greater degree of automation and significant business changes to accommodate the high levels of wind capacity.

179 PPA state within their review of the Irish case study that there are several measures that can be taken to place a *"degree of responsibility on other stakeholders rather than resorting to complex IT solutions."* We agree with this sentiment and have articulated within our March submission that a mixture of different elements such as applying commercial solutions, introducing new processes, recruiting further people and investing in new IT systems culminate in upgrading our capabilities. Like the Irish we are taking these alternative steps to manage the changing environment. Some of these steps for managing greater volumes of wind are listed in the next section.

Role of other stakeholders

180 PPA argues that "*Insufficient emphasis has been placed on the role of other stakeholders"* (Section 3.2, P26). PPA's view is that the market participants should carry more

[4] "Proposed System Operations Services', Payments & Charges in SEM" 24th August 2007

responsibility in terms of balancing their energy positions, such that our reserve requirements can be alleviated. By doing so, PPA asserts that the improvements we are planning for the frequency control systems could be delayed.

181 Whilst we agree that market participants should continue to take responsibility in terms of balancing their position we disagree that this will alleviate reserve requirements. Stakeholders are already incentivised to balance their own positions and this process is frequently reviewed to make sure that it is appropriate. Indeed there is currently a significant code review looking at cash out pricing to look at sharpening incentives to improve security of supply.

182 Any review of cash out has to balance two extremes:

(a) If there is insufficient incentive to balance then it is likely that the TSO will need to make more frequent and costly interventions

(b) Alternatively, if the incentive to balance are too extreme or the regime is excessively complicated this may deter market entry and stifle future competition

183 Irrespective of the structure of any cash out regime, there will always be a residual balancing role that has to be performed by the SO to ensure security of supply and frequency requirements, particularly as we are an islanded system, decoupled from other System Operators.

184 The residual balancing role is due to the imbalance between generation and demand. This is the Net Imbalance Volume (NIV), which itself is the sum of the imbalance positions of all the market participants. These imbalances are due to a number of reasons, such as:

(a) demand forecast mismatch

(b) plant losses (power station trips)

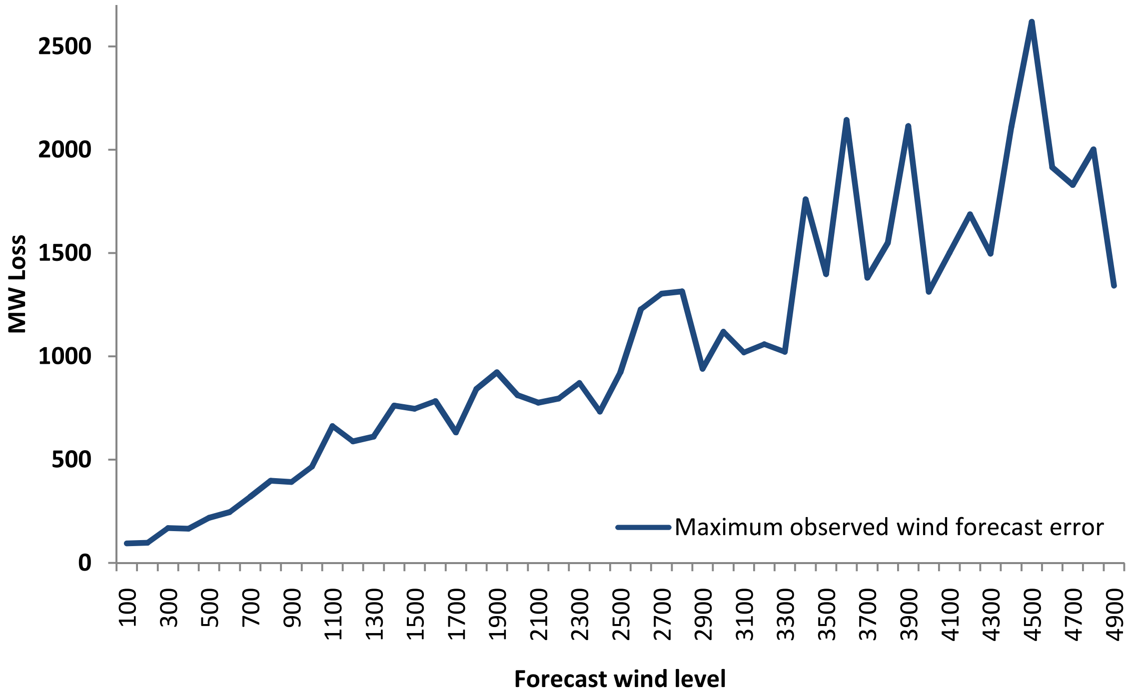
(c) generation output mismatch

(d) due to market behaviour

185 The generation output mismatch is a measure of the difference between the output communicated to us at gate closure (Final Physical Notification) and the actual output. This mismatch is normally more important the higher the variability of the output device and consequently our periodic review of required reserve levels focuses on the effects of wind generation and interconnector flows. Through our analysis we have determined the requirement for additional reserve due to the connection of new wind generation and new European interconnectors.

186 To verify the requirements due to wind generation, we can assess observed data of total output mismatch per settlement period from 1st May 2011 until the end of August this year (15 month sample with over 20,000 data points). By removing the other effects (demand forecast mismatch, plant losses and due to settlement period / market changes) from the total mismatch, we isolate the wind forecast errors (Y axis) and we plot these against the volume of wind forecasted for that settlement period (X axis).

Residual Imbalance due to wind output vs. wind output forecasted



187 The graph shows a dependency between the actual imbalance due to wind and the volume of wind forecasted, consequently illustrating a linear relationship between the amount of wind connected to the system and the reserve we need to hold to secure its imbalance, i.e. wind penetration and costs of integration.

188 This therefore supports the assertion that was made within our operating the system in 2020 document that the balancing requirement placed on NGET will increase three times principally due to wind.

189 PPA stated *"The development of active SMART distribution networks should improve data provision to the ESO rather than present a problem" (Section 3.2.6, p32).*

190 The improved data provision will require a number of business changes to ensure that we receive the right level and quality of information to make the right decisions. The increased information flows will demand significant changes to our operations to ensure we can integrate and manage the volume of data.

191 In conclusion, PPAs concerns that we are taking on *"too much of the burden of market developments without calling on other stakeholders to support the processes necessary to meet the emerging requirements"* seem unfounded. The reality is quite different. Much of the market facilitation role that we undertake involves just such coordination to provide the optimum market solution. To illustrate this, listed below are the various work streams that are currently in flight to manage greater volumes of wind generation:

(a) High Wind Speed cut out: This issue has been raised at the Grid Code Review Panel to address with the intention to place requirements on generators to provide data signals to us on high wind shutdown status; e.g. imminent shutdown, shutdown occurred or re-energisation following cut out.

(b) Encouraging Wind power participation in the Balancing Mechanism: Pursuit of this has involved greater interaction with potential providers, encouraging realistic BM pricing and dynamic parameters, creation of mechanisms to allow bids and offers to be based on 'Power available' and the conversion of < 100MW BELLAs to BEGAs to participate in the BM.

(c) Wind power embedded within the distribution network: Workstream that involves collaboration with DNOs and academia to investigate solutions to the decreasing ability of DNOs to absorb MVar leading to greater constraints. A further project has been established with Western Power Distribution to consider transmission SCADA to Distribution SCADA interface requirements for embedded generation.

(d) Largest Loss and Gain: There is a potential for the loss of power (on wind cut out) or gain in power (from re-energisation) exceeding 1800MW from large offshore wind farms. In this instance there would be insufficient response. We are progressing these considerations within future SQSS.

(e) Provision of rapid Fast Frequency response: Work is being undertaken via the grid code to create a new mandatory service that stipulates primary response being delivered within 5 seconds rather than 10 seconds.

Gas Issues

Overall Approach and Options

192 The opening section of the PPA report appears to contain a number of numerical errors. For example, the first paragraph states average spend over the TPCR4 period was £18.5m (£15m excluding the rollover year). The correct figures are £17.3m and £14.4m respectively.

193 PPA states that '*the IT systems and other infrastructure supporting the gas SO are ageing to the extent that they require imminent and frequent replacement*'. We do not believe we have ever stated in our business plan, or at any other time, that our programme of work is justified on this basis. We have a programme of work that efficiently manages the availability risk of ageing systems, which over the eight year period forecasts multiple system refreshes and replacements based upon an assessment of their age, condition and criticality. This is a point we have responded to PPA on previously.

194 PPA also states that increasing uncertainty over supply and demand patterns are used to justify "*... the greatly increased gas SO Capex programme and the significant investment that is required over the RIIO-T1 period"*. This is incorrect, as only 10% of our investment plan relates to operation in a changing environment (i.e. increased volatility of supply and demand patterns). 54% relates to maintenance of capability and asset health, 18% to Market Regulation and 17% to Shared Services.

PPA Energy View and Concerns

195 One of the core justifications for PPA deferring asset health investment in our plan is that PPA believe *"…that some of the asset refreshes appear to be commencing earlier than the 5 or 6 year period discussed in the asset health policy."* There are demonstrably no asset health projects which deliver ahead of the asset health policy of 5 years for CNI systems, and 6 years for non-CNI systems (see comments under 'Project Analysis – Case 1' below. This paragraph leads PPA to its' erroneous conclusions.

Rationale for Review

196 PPA's stated desire to defer necessary asset health investment programmed towards the end of the RIIO-T1 period takes no account of risks or incremental cost it introduces in terms of reliability and availability of the systems affected, and does not consider the cost / benefit to the end consumer. This is an inappropriate rationale which leads PPA to inappropriate conclusions regarding funding.

197 Deferring some of these investments creates greater network operation risk and/or IT system reliability and availability risk, therefore the statement that the benefits include "*…a more viable workload with less risk…'* is inaccurate. An appropriate assessment of risk impact must encompass the risks associated with not delivering the required capability or asset health deliverable in a timely manner, not just the implementation risk which results from the investment. No such risk assessment has been conducted by PPA.

Main areas of spend in NGG's RIIO-T1 capex programme

198 PPA include a number of numerical errors in this section, including:

(a) iGMS evolution totals [text deleted] in the RIIO-T1 period (not [text deleted] as stated in the PPA report)

(b) Regulatory driven system enhancements totals [text deleted] in the RIIO-T1 period (not [text deleted] as stated in the PPA report)

(c) Telemetry costs are [text deleted] not [text deleted]

Project Analysis

199 We provide below a number of observations on PPA's proposed capex reductions:

(a) iGMS Support Infrastructure Refresh (INVP 3140) is not impacted by the rationale for PPA's Case 1 review (i.e. volatility of supply and demand patterns, asset health investment at the end of the RIIO-T1 period, and rate of regulatory change). It is therefore incorrect that any funding is removed on this basis.

(b) In a number of cases, PPA state that asset health investment appears to commencing sooner than the five year refresh policy, and apply reductions on this basis. In each case, this is an error and must be corrected to provide a fair representation of PPA's analysis. These include:

(i) iGMS Business Applications Refresh (INVP 3197) is a three year project which delivers a refresh, as can be seen from the phasing of investment shown in table 2.12, in 2020/21 which is five years after the delivery of the iGMS Business Applications Replacement (iGMS Evolution) project (INVP 2242) delivers in 2015/16.

(ii) iGMS Enterprise Bus Refresh (INVP 3144) is a two year project which delivers a refresh, per the Estimated Completion Date in table 2.12, in 2019/20 which is five years after the delivery of the iGMS Enterprise Bus Implementation (iGMS Evolution) project (INVP 2692) in 2014/15.

(iii) iGMS SCADA Refresh (INVP 3142) is a three year project which delivers a refresh, per the Estimated Completion Date in table 2.12, in 2019/20 which is five years after the delivery of the iGMS SCADA Replacement (iGMS Evolution) project (INVP 2243) in 2014/15.

(iv) iGMS Data Management System Refresh (INVP 3143) is a two year project which delivers a refresh, as can be seen from the phasing of investment shown in table 2.12, in 2020/21 which is six years after the delivery of the iGMS Data Management System Replacement (iGMS Evolution) project (INVP 2241) in 2014/15. Note we do not consider the data management system to form part of our CNI systems, therefore our policy is to consider a refresh every six years.

(v) GNCC control telephony replacement project (INVP 0538) is a project which delivers on a five yearly cycle (in line with our policy for CNI systems, as control telephony is critical to the continued operation of the GNCC, which is a CNI designated installation). Each refresh to this system is assumed to take 18 months from start to finish and delivers in 2011/12, 2016/17 and 2021/22. This is demonstrably in line with our refresh policy.

(c) iGMS Network Security Enhancements are not impacted by the rationale for PPA's Case 1 review (i.e. volatility of supply and demand patterns, asset health investment at the end of the RIIO-T1 period, and rate of regulatory change). It is therefore incorrect that this funding is removed on this basis.

(d) GNCC Control room infrastructure replacement (INVP 0217) is not impacted by the rationale for PPA's Case 1 review (i.e. volatility of supply and demand patterns, asset health investment at the end of the RIIO-T1 period, and rate of regulatory change). It is therefore incorrect that this funding is removed on this basis.