Power NI Energy Limited
Power Procurement Business (PPB)

DS3 System Services Procurement Design

SEM-14-059

Response by Power NI Energy (PPB)

5 September 2014.

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Power Procurement Business

1.0 Introduction and Summary

Power NI, Power Procurement Business (PPB), is the counter-party to Power Purchase Agreements, which were established in 1992 as part of the restructuring and privatisation of the electricity supply industry in Northern Ireland. PPB purchases both the capacity of the contracted generating units and any electricity generated by those units on terms specified in the agreements.

PPB supports the need for the major review of System Services as there is a requirement for significant changes to be made to the existing market arrangements to: facilitate the increasing levels of renewable generation and the changing generation mix on the island; to ensure flexible generation is adequately remunerated under the new I-SEM arrangements; and to comply with the new Network Codes. It is recognised that renewable energy is justified on economic grounds as a means of correcting the market's failure to incorporate environmental costs in the price of electric generation. However the current market arrangements do not recognise the System Services required to operate a system with a high level of intermittent renewable energy. Increasing levels of wind generation is reducing infra-marginal rent and capacity payments for synchronous generators whilst these generators are also being relied on to provide the flexibility required to manage the system with increasing levels of wind. These synchronous generators are also being obliged to comply with new Grid Code standards, such as ROCOF, with no compensation for the potential new liabilities they will incur as a result of these new standards.

There is a necessity to ensure market arrangements incentivise the right investment decisions, otherwise the necessary flexible and back-up generation will close and not be replaced by new investments, compromising power quality and system security. The considerable work undertaken by the system operators, market participants and regulators in relation to the System Services element of the DS3 programme reflects the complexity and challenging nature of these services and the difficulty in determining an optimum solution for their procurement.

Inherently with challenging problems in the energy industry there is a high degree of risk and the only financial solution can be one which appropriately allocates the risk and reward to all stakeholders (including customers). The electricity supply industry is now facing one of its most radical reforms since liberalisation driven by changes in the regulatory environment; technological innovation and transitions to a low carbon economy. It is therefore important that the transition strategy allows industry to adapt to these changing conditions.

PPB believes that the overall market design, for I-SEM, is becoming unnecessarily complicated for a small market with unique features (e.g. ambitions for high levels of renewable generation, a dominant semi-state generator, etc.). This will create risks and costs for investors and may act as a material barrier to entry especially for smaller generators who may not have the resources (financial and human) to engage in the new market. This is also important for the wider spectrum of stakeholders assessing the I-SEM, for example, institutions providing financing or commodity hedging products. The recent trend for investment banks to withdraw from energy markets due to the increasing regulatory complexity and diminishing financial returns must temper decisions being made by the SEM Committee in relation to the complexity of the I-SEM design (Energy, Capacity and System Services). The focus of plant returns is beginning to shift from the intrinsic value that can be hedged in forward markets to the extrinsic value associated with flexibility. This extrinsic value is hard to quantify and hedge as it relies on factors outside the control of the investor. It is therefore imperative that the overall I-SEM and System Service market arrangements ensure revenue adequacy for all investments, which are necessary to meet overall energy policy objectives. Investors need certainty that the future value of plant flexibility, can be monetised, and that this extrinsic value will outweigh the current inability to earn an adequate return. There is also a risk that the System Service arrangements become too complicated to manage and that the arrangements themselves potentially are the root cause of a deterioration of system security and power quality. The SEM Committee should be cognisant of the relative market size of System Services to the overall I-SEM market (Energy, Capacity and System Services) and ensure that the complexity of the arrangements is proportionate. The existing relativity is €60m for (System Services) compared to circa €3billion for the overall SEM market.

The following points summarise PPBs views of the DS3 System Services Procurement Design:

1) The economic analysis Supply Side focuses <u>only</u> on the costs associated with the enhanced capability which can be provided by the service providers. The procurement is for all System Services required by the TSO and therefore significantly undervalues the cost of System Services. There has also been no comparison with the System Service products which are traded in Synchronous Area (GB).

2) The economic analysis Demand Side focuses <u>only</u> on the value of increasing SNSP and the level of wind connected to the system. It does not value the benefit of all System Services despite the acceptance by all that flexible generators do not currently realise the value of flexibility and with increasing levels of wind may not be able to earn an adequate return.

3) The assessment criteria has a number of material omissions: system security; power quality; welfare redistribution effects; discrimination between technology types and between Service Providers who start providing services either before or after the start of the new arrangements.

4) PPB believes that a market based solution should be selected if, with a reasonable degree of certainty, it can operate with limited regulatory intervention. Otherwise the benefits of a market based solution will not be realised.

5) PPB is concerned that market based options, despite their potential merits in relation to price discovery, will require a high level of regulatory intervention and oversight due to market power concerns. If a competitive market is unable to impose cost discipline then regulation must fulfil that function.

6) Regulated rates must approximate the price that a well-functioning, competitive market would promote for consumers and producers. There are material issues mentioned in this paper which would need to be addressed to ensure a regulated approach will provide investors with the certainty that the future value of plant flexibility and System Services capability, can actually be monetised, and that this plant can earn an adequate return. Without material changes to the revenues realisable for System Services it is unlikely public policy objectives will be achieved and power quality and system security could be compromised.

7) PPB has concerns with the TSOs role in setting regulated tariffs which would need to be managed. One of the perverse proposals in the TSO recommendation paper is that the indicative pot size for Synchronous Inertial Response (SIR) is very relatively low. This translates into a low payment rate. There are similar issues with the relativity of the rates associated with the Ramping Products. A Generating Unit / Interconnector which can provide Active Power within 1 hour must be more valuable to a System Operator than a Generating Unit / Interconnector which takes 3 or 8 hours. However this is not the case in the TSO indicative rates.

8) PPB has a number of concerns with Option 5 which are:
    a. The TSO, as the monopsonist, has the incentive and the ability to reduce, below the competitive level the quantity of service demanded, in order to drive down the price paid. This is possible in the System Services market as the TSO can rely on Grid Code / Connection Agreement obligations to provide System Services with absolutely no obligation on the TSO to pay for this Capability.
    b. With the many constraints in the I-SEM and with the considerable market power issues, it is difficult to understand how the proposed arrangements will work effectively without considerable regulatory intervention.
    c. The SEM Committee relies, to some extent, on homogeneous expectations, which makes their assessment of the procurement options biased towards one which follows clear economic intuition. However many of the products are not homogeneous.
    d. PPB is concerned that the Multiple Bid Auction procurement mechanism that is being proposed by the SEMC will add further considerable complexity to the overall I-SEM arrangements and introduce additional uncertainty for market participants. The auction will require complicated rules for assessment.

9) In an operating environment in which there are considerable exogenous factors, such as the dispatch volume risk which is unpredictable and outside the control of a service provider, the correct apportionment of risk must be achieved by including appropriate availability / capability payments in the remuneration mechanism.

2.1 The Economic Analysis: Supply Side

The proposal by the SEM Committee is supported by economic analysis which has been undertaken by IPA Energy and Water Economics (IPA). The five designs set out in the Consultation Paper are intended to cover the procurement of all System Services required by the System Operators with the exception of Black Start capability. However the supply side analysis focuses only on the costs associated with the enhanced capability which can be provided by the service providers. The SEM Committee estimated that the total capital cost of providing this enhanced capability in 2020 as being in the range €500-€600m (annualised over a 20 year period at a 6.6% WACC to €70m-€84m). This annualised cost is understated since, notwithstanding any argument over the appropriate WACC, it is inappropriate to annualise these costs over a 20 year period as the majority of the investment is likely to be made to the existing generation portfolio with average remaining lifetimes of much shorter durations and there is no certainty that the invest will, under certain options, receive a contract for the full period.

The Consultation paper states that appropriate economic signals are required to "ensure the units of most value to the system are incentivised to enter (and remain on) the system". However the major flaw in this analysis is it ignores the cost of providing the existing System Services and therefore the system services market, if capped by a value relating to the SEM Committee's Supply Side analysis, will not reflect the true costs of providing all of the System Services. The review will therefore not provide investors with the certainty that the future value of plant flexibility, can actually be monetised, and mid-merit plant may not be able to earn an adequate return. The primary objective of the market arrangements should be to ensure the overall local electricity market operates effectively. A sustainable wholesale market framework is required which provides reasonable returns to investors and market participants. This market framework must deliver competitive prices and a secure, reliable and high quality supply of electricity for consumers.
Whilst the SEM Committee recognises, in their consultation paper, that "the three revenue streams (energy, system services and capacity) should work together to provide the appropriate incentives to the market for entry and exit" it is difficult to comprehend how the SEM Committee expects these signals to work if the System Service arrangements to do not accurately recognise the value of the existing System Services.

In order to explore this issue further the table below summarises the efficiencies, based on published Technical Offer Data, of CCGTs which were commissioned on the island of Ireland circa 8-12 years ago.

Huntstown 1	2002	53.45%
Dublin Bay	2002	55.82%
Ballylumford CCGT 20	2003	49.81%
Coolkeeragh	2005	56.53%

The impact of flexibility on a generating units operating efficiency is very clear when Ballylumford CCGT 20 is compared with the other CCGTs. Whilst the configuration of Ballylumford CCGT20 impacts on its overall efficiency the unit provides the system operator with the enhanced flexibility which was required by SONI to securely operate the Northern Ireland system. The capital investment and operating costs (impacting efficiency) associated with a CCGT with a configuration similar to Ballylumford are higher than a large single shaft CCGT. So, if this type of configuration is required in Northern Ireland, to deliver a high level of system security, then the System Service arrangements need to incentivize and remunerate this type of arrangement.

In the absence of a second North South Interconnector SONI must, design and be able to manage the Northern Ireland transmission system with the unexpected loss of generation capacity or an unexpected increase in demand. Based on the analysis which has been undertaken by the SEM Committee the investment signal for Northern Ireland could result in three large single shaft CCGTs (>400MW) to replace existing thermal/CCGT capacity as there is insufficient value being placed on flexibility. These arrangements may not deliver the System Services and flexibility required by the System Operator for Northern Ireland without introducing supplemental commercial arrangements at an additional cost to Northern Ireland customers. Whilst the SEM Committee has reviewed different scenarios for the level of SNSP it has not addressed other major issues impacting System Services, which may have a greater customer impact, such as:

1. Assumptions on size and number of Generating Units necessary in each jurisdiction under different North-South Interconnection scenarios.

2. Assumptions on Reactive Power requirements for major load centres. Three generating units may still be required to be connected in Northern Ireland at all times, even following the commissioning of the second north south interconnector, to ensure voltage stability can be maintained during an N-1 contingency.

Whilst the IPA report identified the €60m costs which are associated with the provision of existing system services the value is not mentioned in the Consultation Paper. PPB has argued in the past that the amount which is currently paid under the existing Harmonised Ancillary Services arrangements is too low. It is neither cost nor value reflective. It had been agreed, during the implementation of the Harmonised Ancillary Service arrangements, that this amount would be reviewed. However this review has never been completed.

IPA stated in their paper that "*our analysis shows that by 2020, the TSOs are expecting the requirements for most existing service products to increase by a factor between 2.6 and 2.9. However, the factors for Replacement Reserve (synchronised and de-synchronised) and for Steady- state reactive power are expected to increase by a factor of about 14.75. In the year 2012/13 a total of €54.2 million of payments were made for existing system services products. Applying the above factors to the costs for system services, based on the 2012/13 tariff levels, would give a figure for total payments of €384 million in 2020*".

Therefore, there is considerable uncertainty in the Consultation Paper in relation to the costs associated with the Supply Side of System Services, which has a material impact on the attractiveness of each of the procurement options.

The other major concern with the analysis is the absence of any commentary on the cost of providing System Services in the GB market. This is particularly strange given the provisions with the Network Code on Load-Frequency Control and Reserves. Under this Network Code there are provisions for the exchange of: Frequency Containment Reserve, Frequency Restoration Reserve and Reserve Replacement between Synchronous Areas. It is important that the System Service arrangements do not result in either: (1) re-distribution effects between the two synchronous areas or (2) discrimination between system service providers to/from Synchronous Area (Ireland). On this latter point if East-West or Moyle Interconnectors were to restrict capacity in order to provide Reserve contracted from Synchronous Area (GB) they should be treated the same as other System Service Providers. For example, if reserve is paid for only if it is activated then Interconnectors should not be entitled for capability or availability payments if other System Providers cannot realise capability or availability payments. This principle is extremely important given the independence concerns relating to the ownership and operation of the East West Interconnector. The following paragraphs summarise some of the System Service prices in GB in June 2014. Whilst some of the products are not directly comparable the prices provide a benchmark of the System Service prices in the only market which is coupled to the SEM.

Replacement Reserve Price Comparison
For June 2014 the outturn and contracted figures for Short Term Operating Reserve (STOR) paid by National Grid (GB) are shown in the table below. The existing SEM Harmonised Ancillary Service Rate is €0.53/MWh. In the further analysis completed by the TSO for the SEM Committee the DS3 Rate is €0.09 / MWh based on a €100M pot.

	Outturn	**Contracted**
Volume weighted average availability price	£5.01/MWh	£4.25/MWh
Volume weighted average utilisation price	£119.59/MWh	£170.42/MWh

Primary Frequency Response Price Comparison
For June 2014 the holding fee for Mandatory Frequency Response (Primary) paid by National Grid (GB) was £3.40/MWh. The existing SEM Harmonised Ancillary Service Rate is €2.31/MWh. In the further analysis completed by the TSO for the SEM Committee the DS3 Rate is €3.5459 / MWh based on a €100M pot.

For June 2014 the fee for Commercial Frequency Response, paid by National Grid (GB), was £34.66/MWh. The existing SEM Harmonised Ancillary Service Primary Operating Reserve Rate is £2.31/MWh. In the further analysis completed by the TSO for the SEM Committee the DS3 Rate is €3.5459 / MWh based on a €100M pot.

Reactive Power Price Comparison
For Summer 2014 the Default Payment Mechanism for Reactive Power paid by National Grid (GB) was £3.00/MVarh. The existing SEM Harmonised Ancillary Service Rate is €0.13/MVarh. In the further analysis completed by the TSO for the SEM Committee the DS3 Rate is €0.19 / MVArh based on a €100M pot.

2.2 The Economic Analysis: Demand Side

The most material observation of the demand side economic analysis is that it only considers the incremental value associated with operating a system that can facilitate higher levels of installed wind and System Non Synchronous Penetration. However the SEM Committee is proposing procurement options for all System Services including the existing products required to ensure a secure and reliable system operating under existing constraints. The review will therefore not provide investors with the certainty that the future value of plant flexibility, can actually be monetised, and mid-merit plant may not be able to earn an adequate return. Whilst the all-island market may have sufficient capacity, the generation mix on the island may be insufficient to ensure system security and power quality at all times which could result in: load shedding; blackouts; or material detrimental impacts on power quality.

Whilst the SEM Committee analysis has focused on the cost of enhanced capability and value to customers from increasing SNSP from 50% to 75%, it has not considered the costs associated with existing constraints which are greater than €160m p.a. The difference between the market schedule and actual dispatch identifies some of the limitations of the most efficient plant in providing system services. The SEM Committee should have, as part of the review of all the System Services, found the optimum solution of incentivising investment in System Services which will lower the existing constraint costs.

One example of this is dynamic reactive power. It is common that market pricing of reactive power is by marginal pricing and with no locational weighting. However this will not result in sufficient compensation to the providers of the service, it will lead to lower reliability, and it will not incentivise location in the right electrical area. Optimising constraints costs associated with maintaining voltage stability will not be achieved.

3.1 Assessment Criteria - System Security and Power Quality

PPB is concerned that the SEM Committee, the Regulators and their advisors do not fully understand the engineering challenges associated with operating the Northern Ireland and Republic of Ireland Transmission Systems. This is evident from the assessment criteria, which is limited to: Consumer interest; Investment; Curtailment; and Renewable Targets with no criteria to assess the satisfaction of either System Security or Power Quality standards in each jurisdiction. Whilst reducing curtailment and achieving renewable targets are important, the most important consideration for system services must be ensuring system security and power quality, whether or not the renewable targets are met. Whilst System Services are not separately distinguishable by customers in their electricity supply they are implicitly consumers of such services through the continuity and quality of the supply they are receiving. The SEM Committee should seek information from the TSO of the different levels of power quality which could be expected under different volumes of System Services. There should be criteria set in relation to the level of system security and power quality which is expected and if this is not being met then it is an indication that insufficient levels have been contracted. The proposals at the moment are one sided as they incentivise the TSO to procure the services efficiently with no obligation in relation to system security or power quality.

Eirgrid and SONI have licence obligations to ensure sufficient system services are available to enable efficient, reliable and secure power system operation. This may be difficult to achieve if the TSOs are directed to procure System Services using an inappropriate mechanism. The design of the small islanded electricity system in Northern Ireland and Republic Ireland has presented serious engineering challenges for decades. In Northern Ireland the risks were identified in a major Government enquiry into the “Characteristics of the Electricity Supply System in Northern Ireland” which was undertaken after serious disruptions to electricity supplies in the 1970s. The situation was of such a material nature that system stability issues were a major concern as insufficient availability of generating units could have resulted in difficulty in controlling voltage and other key technical considerations.

Many of the risks to system security, which were present in the 1970s, still exist today. Northern Ireland has a small electricity system with currently a maximum peak demand of circa 1800MW and a minimum demand of circa 500MW. The output from a single large generating unit can be supplying a large proportion of the Northern Ireland demand, relative to other electricity systems. Therefore the loss of the single largest credible contingency has a potentially much greater impact on system security in Northern Ireland than in other Transmission Systems in the rest of Europe. Neither the TSO nor the SEM Committee have identified the unique technical constraints in Northern Ireland and whether, for example, system security could be assured by, for example, three large CCGT plants (400MW) and whether this arrangement could guarantee system security standards in the new Network Codes.

The Operational Security Network Code (OS) will provide the basis for the power system to function with a satisfactory level of security and quality of supply, as well as efficient utilization of infrastructure and resources. Northern Ireland and the Republic of Ireland will need to comply with the Frequency Quality Defining

Parameters which define the acceptable ranges for System Frequency after the occurrence of a Reference Incident. The size and duration of System Frequency deviations determine the frequency quality. The Network Code on Frequency Control and Reserves states that maximum number of minutes outside the Standard Frequency Range in Synchronous Area (Ireland) should be 10500 (175 hours). This is more stringent than Synchronous Area (GB) despite the more robust nature of Synchronous Area (GB).

The impact of insufficient system services is not limited to potential lost load but also a reduction in the quality of the electricity power supply which in extreme cases could lead to a catastrophic failure of plant and apparatus. Consumers could experience power quality reductions, such as transient voltage surges; phase angle distortion; frequency and harmonic issues. The benefits of frequency control include the avoided costs of loss of industrial production, community disruption and inconvenience and equipment damage.

Consumers could install protective equipment to mitigate some of the issues relating to voltage variations. London Economics in their paper entitled “The value of Lost Load (VoLL) for electricity in Great Britain” have identified some of the potential cost impacts, such as the cost of protective equipment; the opportunity cost of consumers’ devices shutting down and having to be re-started or reset; the additional wear and tear on appliances and devices of a typical household and the cost implications of the same. The TSO and the SEM Committee are therefore making decisions in relation to the market arrangements for investments which help manage power quality. The failure of this market could have significant costs for customers and generators connected to the electricity system. Northern Ireland businesses currently pay the second highest electricity prices in Europe. It would be unacceptable if in addition to paying higher costs the security or quality of power supply was inferior.

Average Cost of Surge protection per household	£172.33	£5.84 / MWh
Opportunity Cost per shutdown per household for re-setting appliances due to voltage induced shutdowns	£1.61	
Cost of household (reduced lifetime of appliances) of 1 hour voltage sag of depth 86% (£/MWh)		£807.60/MWh

3.2 Assessment Criteria - Redistribution between jurisdictions

There is potentially a material welfare redistribution effect between the two jurisdictions which has not been addressed by the SEM Committee. There are potential positive externalities on either jurisdiction as a result of either historical or future decisions which have been made by the other jurisdiction. For instance, the standards adopted in one jurisdiction to ensure system security may benefit the security of the neighbouring jurisdiction, for example, if a Grid Code requires a higher standard for a generating unit. The jurisdictional differences in System Planning and Grid Code Standards must be considered as part of the assessment of the procurement and payment options. Choices in generation and transmission, and indeed the gas network, exhibit a high degree of interdependency and therefore investors in power stations are constrained in their choices by the architecture of the gas and electricity systems and also the standards with which they must comply.

When the electricity industry was privatised in Northern Ireland the transmission system was still self-contained as neither the North South interconnector (re-commissioned in 1995) or the Moyle Interconnector (2002) were available. The legal framework that was put in place at the time of privatisation ensured the safe, secure, efficient and reliable operation of the high voltage electricity system in Northern Ireland. The Grid Code is a key piece of the legal framework which ensures the strict technical requirements of generators which are connected to transmission system are observed. Northern Ireland still has a small electricity system with currently a maximum peak demand of circa 1800MW and a minimum demand of circa 500MW. The output from a single large generating unit can be supplying a large proportion of the Northern Ireland demand, relative to other electricity systems. The loss of a single generating unit has had the potential to cause system stability issues which require measures which are not necessary in larger systems.

The reserve requirements for generators connecting in Northern Ireland are an example of potential welfare distribution. These requirements were designed to provide the System Operator of Northern Ireland with the necessary flexibility to manage a small system such as Northern Ireland. The generating units were designed for unpredictable high impact scenarios, such as a without notice trip on a generating unit. Wind, whilst it is variable, can be forecast with higher confidence levels than the tripping of a large CCGT or interconnector as a result of a fault or mal-operation of protection.

The table below illustrates, just one example, of the differences between the standards in the Northern Ireland and Republic of Ireland Grid Codes. If the TSO can rely on the legal requirements contained within connection agreements and grid codes without any obligation to pay for reliance on the capability or utilisation of the System Service then there is a risk of welfare distribution from Northern Ireland to the Republic of Ireland.

Grid Code Requirement	ROI CCGT/Thermal	NI CCGT (MFS)	NI Ballylumford B31 and B32
Primary Operating Reserve	5% of Max Capacity	10.8% of Max Capacity	18% of Max Capacity
Secondary Operating Reserve	5% of Max Capacity	18% of Max Capacity	19.2% of Max Capacity
Tertiary Operating Reserve 1	8% of Max Capacity	18% of Max Capacity	19.2% of Max Capacity
Tertiary Operating Reserve 2	10% of Max Capacity	18% of Max Capacity	19.2% of Max Capacity

The Figure below, provided courtesy of Eirgrid Group, shows how the reserve requirements have softened in the Republic of Ireland and that most generating units now have reserve capabilities significantly below those in Northern Ireland.

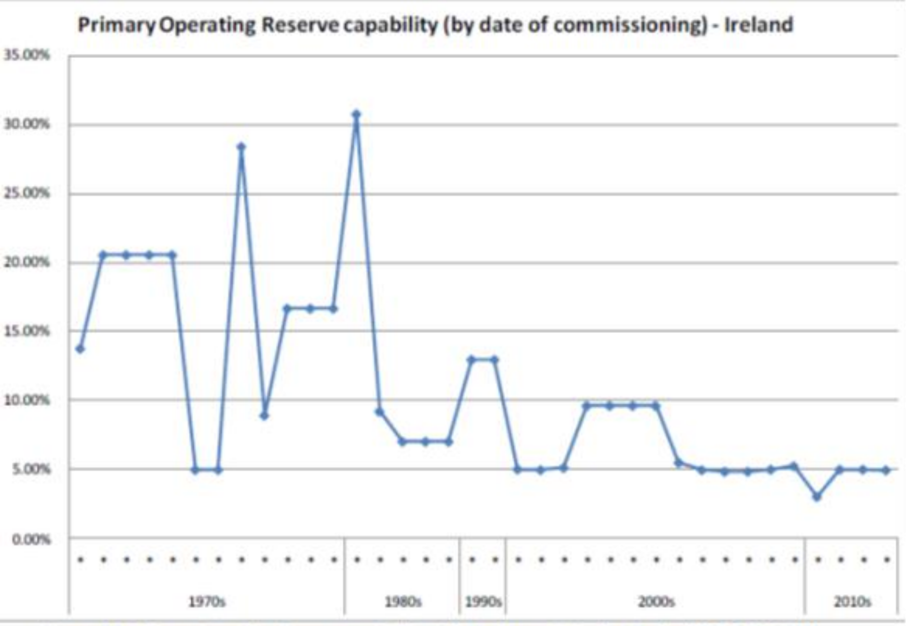

Figure 14: Primary Operating Reserve capability at date of commissioning (Ireland) (EirGrid, 2011)

There are other areas where SONI has stipulated significantly higher requirements for generating units connecting to the Northern Ireland system. For example, Ballylumford CCGT20 was designed, and is a grid code requirement, to operate with low minimum generation levels, high ramp rates, and being capable of starting up quickly in (or switch to) open cycle mode. In addition to the technical capabilities, of CCGT20, the multi-shaft configuration has a lower total blackout probability than a single shaft CCGT. The availability and reliability of this configuration of CCGT is also generally higher. This is due to the different operation and outage scenarios for both configurations as there can be independent planned outages of the GTs which leads to a higher availability and reliability than if it were a single shaft CCGT.

The potential effects of welfare distribution between jurisdictions, because of differing standards, must be carefully considered and may need some form of compensation arrangements.

3.3 Assessment Criteria – Discrimination between Providers

The SEM Committee assumes that the System Services should be technology neutral and should not be predicated by winners and losers. This truism is often cited by policy makers proposing new market arrangements. However the Grid Code already differentiates between technology types and the System Service standards that are expected from each of these types. It is discriminatory to oblige certain technology types to provide superior levels of System Services and then for the TSO not to pay for this superior standard. This could lead to legal challenges on the grounds of discrimination against the TSO conducting the procurement process as the TSO has effectively set different pre-qualification requirements for different technology types. The TSO also has the optionality to disregard a bid, for a Service Provider, based on the knowledge that it can avail of the System Service for free without a System Service contract. If the SEM Committee is actually advocating a technology neutral procurement process it must specify, for each System Service, that the lowest Grid Code standard across the technology types (interconnector, thermal generation, CCGT, OCGT, pumped storage) must set a minimum threshold above which payments must be made. The TSO has already contractually obliged, either in a connection agreement or in the Grid Code, a Grid Code User to provide a certain volume of System Service which is not consistent between Grid Code Users and technologies.

Under some of the procurement options the SEM Committee is advocating unfair discrimination between existing and new System Service providers. A System Service Provider who has commissioned its plant/apparatus before the effective date for the new arrangements may not be entitled to recover the capital costs associated with the System Services whereas a Service Provider who commissions a new System Service after the effective date will be able to recover the capital costs it incurs if it wins the bid. This could also lead to discriminatory effects in the proposed new Capacity Reliability Option market between participants who have invested before and after the effective date of the new System Service arrangements. It is likely that this could lead to a legal challenge.

4.0 Procurement Options

PPB acknowledges the challenges associated with identifying suitable procurement options and selecting the optimum solution for the all island energy market. PPB believes that a market based solution should be selected if, with a reasonable degree of certainty, it can operate with limited regulatory intervention. Otherwise the benefits of a market based solution will not be realised. The GB system service rates, summarised earlier in this response, identify some of the disparities between market and regulated prices (both existing HAS rates and DS3 indicative rates). There is a risk that a regulated option will result in significantly lower prices than a market based solution, especially if the SEM Committee bases the total System Services pot on the costs identified in its Supply Side analysis.

PPB has concerns that the TSO lacks the necessary information for making informed decisions in relation to its role in setting regulated rates. This would need to be very carefully managed. One of the perverse proposals in the TSO recommendation paper is the indicative pot size for Synchronous Inertial Response (SIR) which translates into a low rate. SIR is the response in terms of active power output and synchronising torque that a unit can provide following disturbances. It is a response immediately available from synchronous generators and mitigates the risk of high rates of change of frequency on the system. Inertia should be incentivised to ensure ROCOF events do not happen in the first instance. Synchronous Area (Ireland) will have to comply with frequency quality requirements in the new Network Code. It would appear contrary to the spirit of the Network Codes if a regulated tariff for inertia was set at such a low rate. It is difficult to comprehend the reasons behind recommending such a low pot other than the fact that Eirgrid, as owner of an interconnector asset which cannot provide inertia, has skewed the results towards an outcome that is more favourable to interconnectors. This will result in essential Generating Units with high levels of inertia having limited or no advantage when bidding for capacity in the I-SEM (if the reliability options are progressed). This will result in the wrong entry and exit signals from I-SEM.

Product	Total Payment (€) TSO €355m POT	Response Time	Relative Value - managing quality of system frequency (1 -2 , High –Low)
SIR	8,000,000	Immediately on power imbalance mitigating impact on quality of frequency	1 (rate too low relative to value for managing system frequency)
FFR	41,000,000	2 seconds after detection of a frequency event (i.e. frequency deterioration has already occurred)	2

There are similar issues with the relativity of the rates associated with the Ramping Products. The rates for RM1, RM3, RM8 are €0.8751/MWh, €1.5918MWh, and €1.1316/MWh respectively. A Generating Unit / Interconnector which can provide

Active Power within 1 hour must be more valuable to a System Operator than a Generating Unit / Interconnector which takes 3 or 8 hours. The opportunity cost of customers being off supply for an additional 7 hours must make the case for RM1 attracting the highest rate.

PPB, as discussed in the next section, is concerned that market based options, despite the potential merits in relation to price discovery, will require a high level of regulatory intervention and oversight due to market power concerns. If a competitive market is unable to impose cost discipline then regulation must fulfil that function. However, the regulated rates must approximate the price that a well-functioning, competitive market would provide for consumers and producers. The material issues mentioned above would need to be addressed to ensure a regulated approach will provide investors with the certainty that the future value of plant flexibility and System Services capability, can actually be monetised, and that this plant can earn an adequate return. Without material changes to the revenues realisable for System Services it is unlikely public policy objectives will be achieved and power quality and system security could be compromised.

5.0 Option 5: Multiple Bid Auctions

The proposed competitive market must be assessed by its proximity to perfect competition, which has been shown to assure the most economically efficient outcome. There are several prerequisites for competitive markets to operate efficiently. Perfect competition requires an industry with numerous buyers and sellers of a virtually identical product. No seller or buyer has market power (which is to say that the production or consumption decisions of any one seller or buyer will have no effect on overall supply or demand and, therefore, no effect on price). Buyers and Sellers should also have access to all relevant information.

Assessing the System Services market using this framework identifies a number of material challenges.

- **Single Buyer**

The TSO, as the monopsonist, has the incentive and the ability to reduce, below the competitive level, the quantity of service demanded in order to drive down the price paid. This is possible in the System Services market as the TSO can rely on Grid Code / Connection Agreement obligations to provide System Services with absolutely no obligation on the TSO to pay for this Capability. Service Providers will receive lower payments and not those which could be realised in a perfectly competitive market. This concern is compounded as the TSOs will be commercially motivated to reduce the quantity of services demanded because of the proposed TSO incentive arrangements. The TSO can set a threshold that will effectively act as a cap on the market price. This is likely to happen if the Regulators set a market cap based on their Demand and Supply side analysis. It is also likely to happen if the existing HAS rates are used as a cap on prices. As System Service providers cannot easily relocate their capacity to serve alternative locations and buyers, they are therefore exposed to this monopsony risk and regulatory risk.

The TSO could establish arrangements to exchange Reserve with Synchronous Area (GB) having procured these System Services from System Service providers connected to Synchronous Area (Ireland). The TSO could therefore arbitrage between the two System Service markets having artificially lowered prices in Synchronous Area (Ireland).

The interests of the intermediate user of the ancillary service, the TSO which is the monopsonist, and the end user can diverge as the monopsonist with buyer power does not guarantee a better deal for current and future customers. This is because the medium / long term of interests will not be protected.

If the TSOs have specified a level of System Service in a Grid Code they need to pay the Grid Code User for the capability of providing these System Services.

Highly Concentrated Supply Side

With the many constraints in the I-SEM and with the considerable market power issues, it is difficult to understand how the proposed arrangements will work effectively without considerable regulatory intervention. The IPA report which accompanies the SEM Committee Paper discusses market power on an all island basis, however it does not consider the ability for a participant to exert market power in a smaller geographical or electrical area. For example, voltage support for Belfast can currently only be provided by generating units operated by AES. There are similar issues for reserve and inertia in Northern Ireland.

The table below identifies some of the local market concentration concerns in Northern Ireland. These local market concentration concerns are not unique to Northern Ireland and are also present in Dublin and in other locations on the Island.

	SONI Transmission Constraint	Northern Ireland HHI based on ownership	Northern HHI based on Commercial Contract
Synchronous Inertial Response	System Stability There must be at least 3 high inertia machines on load at all times in NI. Based on new SIR product it is likely that only 4 Units can provide this product. All 4 units are owned by AES.	10,000 (Monopoly)	>5,000
Dynamic Reactive Response	Belfast area North West Generation	10,000 (Monopoly) 10,000 (Monopoly)	10,000 (Monopoly – based on Kilroot only) Greater than 5,000 if Ballylumford is included. 10,000 (Monopoly) based on Coolkeeragh ESB.
Primary Operating Reserve	50MW Minimum from Synchronous Generators C30, B31, B32, B10 (limited reserve) K1 and K2 Open Cycle Units (peaking units with limited running)	>5000 at all times	>3267 at all times

- **Heterogeneous Products**

The SEM Committee relies on homogeneous expectations, which makes their assessment of the procurement options biased towards one which follows clear economic intuition. However this thesis fails to take account of the heterogeneity of the system service products. This will make the allocation rules in a Vickrey Auction difficult as the products offered by each Service Provider are not always perfect substitutes.

- **The Vickrey Auction**

PPB is concerned that the Multiple Bid Auction procurement mechanism that is being proposed by the SEMC will add further considerable complexity to the overall I-SEM arrangements and introduce additional uncertainty for market participants. Under the proposed system services there will be at least 14 products some of which will have material interactions with the energy (such as the ramping products) and capacity markets. Whilst the Vickrey mechanism is popular with theoretical economists their practical applications are not very common. Despite the theoretical virtues of the mechanism, it has weaknesses which limit its practical application. The weaknesses in the design are as follows:

1. The mechanism is very complicated and will require a system to be built to assess the bids. If the SEM Committee is reluctant, as it would appear, to let the System Services market grow much from its existing size then this added complexity is not warranted.
2. Sellers could receive very low or zero revenues (which is contrary to the objective of trying to rebalance the revenues between flexible and inflexible generation)
3. The Vickrey mechanism will require complicated rules to determine the optimum solution.
4. The allocation of System Service contracts may not be transparent to sellers due to the complicated rules in the auction which are invariably subjective.

The dominant strategy property is one of the main advantages of the Vickrey Auction as it limits the resources spent by bidders working out competitor's strategies. However given the proposal for remuneration of capacity by way of Reliability Options, knowledge of competitors bidding strategies could be important. Existing investors in the SEM have made significant capital investments on the Island and need sufficient revenues from the new I-SEM arrangements to ensure they make adequate returns on their investment. If an investor in the I-SEM gets its strategy in the System Service and Capacity Auctions wrong, it could be pushed into financial distress. Therefore bidders will be tempted to skew their bid below their cost, in the System Services market, in order to have a greater chance of winning System Service contracts, but this will have longer term implications for investment in the I-SEM.

As the Vickrey Auction is assessing all System Services (existing and new) the proposed arrangements are discriminating between (1) Service Providers who are providing System Services to the TSO, either in HASA or to comply with Grid Code obligations, prior to the effective date of the new arrangements and (2) Service

Providers who will start to provide System Services after the effective date. If, for example, a CCGT is built just before the start of the new arrangements there is now no guarantee that the CCGT can recover its investment costs as the SEM Committee state "*If the existing portfolio could meet the TSOs requirements no long term contracts would be entered into and prices would not have to facilitate investment costs*". The SEM Committee is therefore assuming that before the start of the new arrangements existing service providers will have paid off all the investment costs associated with their capability of providing System Services. Existing units which are flexible and provide high levels of System Services will be put at a disadvantage when it comes to bidding in the proposed CRM as they will still have to recover the significant capital costs associated with capability to provide flexibility and System Services.

The Vickrey Auction protects entities who are looking to make new investments after the effective date of the new System Service arrangements as the optimum strategy in a Vickrey Auction is to bid your value. If you do not win you do not invest and therefore there is no risk of having to write off your investment (albeit there is significant risk from products which are dispatch based).

6.0 Payment basis for the services

In an operating environment in which there are considerable exogenous factors, such as the dispatch volume risk associated with variability of wind, which is unpredictable and outside the control of a service provider, or events on the system, the correct apportionment of risk must be achieved by including appropriate availability / capability payments in the remuneration mechanism. Service Providers require certainty in relation to the revenues they expect for their capital investment as commercial uncertainty of investing in the all island electricity market is likely to damage investor confidence possibly impacting the cost of capital, which could eventually feed through into higher prices to customers.

Operating Reserve and Replacement Reserve

A remuneration mechanism based purely on dispatch based payments inappropriately places all of the commercial risk associated with investing and maintaining the system service with the investor. The SEM Committee concur with this and state that “it is likely to be unsuited to products that are infrequently, or unpredictably, used and are integral to the technical design of the unit. In other words the unit provides a service by simply being there but the actual need for the service only occurs infrequently (if there is a fault for example).” However under most of the Procurement Design Options the SEM Committee is proposing to pay Operating Reserve and Replacement Reserve (Synchronised and De-Synchronised) on a Dispatch basis (defined as “As Used”). Given that Frequency Events are currently infrequent, payment on a dispatch basis is inappropriate and contrary to the SEM Committees opinion that such a basis is unsuitable for products which are infrequently, or unpredictably used. Unless, of course, the SEM Committee believes that the new System Service mechanism will result in a significant deterioration of the Power Quality which customers currently experience and Frequency Events are due to become common occurrences.

It is also unlikely that the TSO will be able to rely on Reserve from Synchronous Area (UK) without paying National Grid a Holding Fee. This will therefore raise legal questions if the TSO discriminates between System Service Providers (which would include National Grid) if it pays National Grid a holding fee for reserve and only pays System Service Providers, in Synchronous Area (Ireland) if the Operating Reserve is utilised.

In each half hour trading period it is the: Availability of the Operating Reserve; Availability of the Replacement Reserve Synchronised; and the Capability of the Replacement Reserve Desynchronised, which is important to the System Operator. The Availability or Capability of these categories of Reserve allows the System Operator to dispatch a larger infeed (interconnector or generating unit) on to the small island system. There is therefore considerable value associated with the Availability or Capability of Operating and Replacement Reserve in each half hour trading period. Replacement Reserve (desynchronised) is hugely valuable to the TSO as it is capable of synchronising to the system and providing Replacement Reserve within 20 minutes without having to incur on-going energy costs.

Ramping Margin

The capability of a Generating Unit, not synchronised to the system, to provide RM1; RM3 and RM8, is extremely valuable to the TSO. This capability allows the TSO to dispatch higher levels of wind with an option to dispatch generation which has the capability of synchronising to the system and replacing any decrease in wind output within the relevant product timescales. This is much more valuable than a generating unit which can only provide Ramping Products if it is synchronised to the System.

PPB would propose that two categories of Ramping Margin Payments are designed (1) Synchronised which is Dispatch Based (2) De-Synchronised which is Capability Based. This is similar to the rational behind the two Replacement Reserve products.

SIR

Given the importance of SIR it should be paid on a capability basis. In Northern Ireland, for example, only a limited number (4) of the Generating Units are capable of being rewarded for their inertia. Given the need for at least three large inertia Generating Units to be synchronised in Northern Ireland at all times, and the need to plan for outages, it is imperative that all Generating Units which meet the technical requirements for the product are remunerated on a capability basis.

Performance Penalties

The SEM Committee has not given any consideration to undertaking a review of the Generator Performance Indicators. It is important that both risk and rewards are reviewed. Issues such as the introduction of a material GPI for non-performance against ROCOF standards significantly changes the risk/reward balance.

7.0 Interaction with I-SEM

The interplay with I-SEM arrangements adds considerable complexity.

Balancing and Ramping Products

The interaction between DS3 and I-SEM has not been fully considered and it is vital that the DS3 arrangements are an integral part of the overall I-SEM considerations. For example the ramping products of 1, 3 and 8 hour durations could have a material impact on balancing markets. The balancing market proposals in the I-SEM High Level Design are not well defined and it is unclear how marginal pricing will be determined given actions could be taken by the TSOs at any stage following the closure of the DAM.

Scheduling and Dispatch

In paragraph 6.4.32 of the I-SEM High Level Design it is stated that "generators will 'learn' how to bid" to achieve an outcome, while in Annex B paragraph 1.5.10, it indicates that "The generator then creates a Profiled Block Order to reflect the desired production pattern of the unit". PPB has significant concerns that this will allow considerable market power in both the energy and system services market. The proposed arrangements create significant information asymmetry and the net effect is that additional market power mitigation measures will be required to offset the additional benefits conferred to portfolio generators by the proposed design of the energy and system services markets.

Proposed Ancillary Service and Capacity Mechanism

The combination of novel and complicated approaches in relation to CRM with the proposed complicated design of the procurement of the System Services is not warranted for the I-SEM and adds to already complex arrangements. The market concentration of generation in Ireland with a large participant with a portfolio of mixed technology generation would inevitably distort any CRM and System Service auction process. The RAs will therefore need to define and monitor arrangements to ensure market power cannot be exercised which will in itself impact on the market and increase regulatory risk for investors operating in, or new investors considering entry to, the market.

DS3 and Forwards Markets

The interaction of the DS3 contracts with the energy market will also make price forecasting in the forwards markets more complicated and may make it more difficult for buyers and sellers to reach price convergence.