Chapter 1

1. Do you agree with these three core principles?
   - **Principle 1**: The DSO must run its business in a way which reflects the reasonable expectations of network users and other stakeholders.
   - **Principle 2**: The DSO must act as a neutral market facilitator in undertaking its core functions
   - **Principle 3**: The DSO must act in the public interest, taking account of costs and benefits.

The Institution of Engineering and Technology (IET) agrees that the three core Principles as cited in the consultation are basically sound. However, from a Great Britain (GB) DSO perspective, Principles 1 and 3 are somewhat superfluous as these requirements are already embedded in existing Codes, Statutory Instruments and Distribution Licence obligations. However our view is that Principle 1 should extend to the reasonable expectations of future users and stakeholders which might be quite different than today. For example, it is anticipated that users in GB will tend to buy energy management systems that operate on the consumer side of the meter and are likely to be asynchronous in operation to the rest of the grid. The control of demand and local generation will therefore be to optimise the user’s requirements and not that of the DSO. Opting in to demand side response management will therefore be only one option; there will be many products that provide other more localised options. Principle 1 therefore will need to consider what is “reasonable expectations” in this context.

In GB, the behaviours described by Principles 1 and 2 are strongly incentivised through the GB regulatory framework (RIIO ED1). This includes a strong focus on incentivising innovation and outputs. Examples of outputs are provided in our response to question 14.

Principle 2 is assured to some extent in GB by Licence obligations surrounding business separation which place restrictions on DSO activities that might
undermine the benefits to consumers of competitive markets. However, the DSO, whilst acting as a neutral market facilitator, should also be a facilitator of innovation and new market entrants.

Overall, our view is that these Principles do not adequately capture the emerging role of a DSO as perceived in Great Britain by the utility sector. Our view is that DSOs can make an important contribution to the economic operation of the electricity system, not only through the efficient delivery of its core activities as a ‘passive’ network operator and ‘market facilitator’, but also increasingly as an ‘active’ network manager and system service provider. We expand on this point in our response to question 5 below.

2. What challenges would new forms of stakeholders (e.g. community or municipal energy schemes and ESCOs) bring to DSOs and to existing approaches?

In general, we would regard new forms of stakeholders as an opportunity for a DSO to leverage any inherent distributed energy resource (such as generation or energy storage) or energy management capability (such as DSR through time-of-use energy pricing and potentially smart appliances) to improve the efficient utilisation of the distribution network (for example by improving load factor which in turn could free-up network capacity and reduce peak-driven network losses). This then has to be balanced with the wishes of the end user, as indicated above, who may wish to use energy management systems that run asynchronously to the DSO’s expectations.

We also note and agree with the suggestion that DSOs should be allowed to design and set distribution tariffs to influence consumer behaviour. However, in GB, DSOs will remain dependent on Suppliers to reflect any price signals in their energy tariffs. In practice that means Suppliers offering Time of Use tariffs and passing through any time of use distribution pricing in the tariff. In practice, Suppliers are likely to offer Time of Use tariffs to domestic consumers only once half-hourly settlement based on actual (as opposed to profiled) half hourly consumption is introduced. That in turn of course depends on the successful roll out of a national smart metering system.

However, in circumstances where intermittent low carbon generation is a major component of the electricity system (as is envisaged for GB) then the focus for Suppliers, ESCOs and Commercial Aggregators will be towards aligning demand with real-time availability of low marginal cost generation and avoiding periods where high marginal cost peaking plant has to be dispatched. This envisaged more dynamic nature of future demand profiles might give rise to less predictable (and under some circumstances possibly higher) network peaks. In GB there is a very large community of local authority and housing associations that have installed large amounts of solar PV on social housing stock where the commercial aggregator is less likely to operate. These consumers are more likely to suffer with fuel poverty issues and are less likely to respond to voluntary time of use tariffs. This can result in large clusters of unconstrained solar PV generation and hence potential constraints on networks. This will add to the complexities of the DSO’s management of the network.
It follows that whilst DSOs might benefit in general from incentives on consumers and communities to reduce peak demand period energy consumption, they must also plan for circumstances (typically periods of low demand and high solar PV and wind generation output) where network demands might be higher than traditionally experienced under ‘flat’ tariff structures.

Whilst the question relates to the challenges that new forms of stakeholders might bring to DSOs, it is important to recognise that DSOs, in addition to the many third party advisors who have also advised communities and DSO’s to date, have an opportunity to be expert advisers to energy communities in terms of principles of design and operational safety for energy infrastructure. Regulation should ensure that DSOs are incentivised to facilitate Community Energy schemes and maximise the mutual benefits that co-ordination in design and operation between the existing network and the Community Energy system could bring.

3. Do you agree with the proposed logical framework? Are there other important questions which should be included in the framework?

In terms of the proposed ‘Framework’ and ‘Activities of DSOs’ (sections 1.2 and 1.3) it follows from the above that there are circumstances where a DSO might be able to offer competitively priced services to the Transmission System Operator which will ultimately benefit consumers. It should also be noted that there are circumstances wherein it is directly in customers’ interests for DSOs to be allowed to compete. For example, in GB the provision of new connections (including extensions of the distribution network to provide new connections) is open to full competition from Independent Distribution Network Operators (IDNOs) and Independent Connection Providers (ICPs). Hence a customer (for example a developer or distributed generator) is able to approach the incumbent DSO, and ICP and an IDNO to secure the most competitive offer. It would clearly not be in customer’s interests for the DSO to be precluded from offering a competitive quotation.

From a wider perspective, it is important to recognise that ‘ unbundling’ was an imperfect step in the early days of deregulation and sector change. With the benefit of experience and hindsight there might now be merit in exploring opportunities for DSOs to have a broader engagement role whilst still protecting market principles – for example by stipulating caps on energy services traded or by ring-fencing specific activities. In this regard, Annexe 4 is a cause for concern and could potentially jeopardise the opportunities for DSOs to make a valuable contribution to overall system efficiency in areas such as energy storage management and aggregation of Virtual Power Plant (VPP) and DSR services.
4. Do you agree with the proposed assessment of activities and are there any additional grey areas for DSOs other than those considered?

In terms of DSO activities excluding ‘generation’ and ‘supply’ we feel that it is important to clarify that the exclusion relates to the energy market (wholesale and retail activities). There might be legitimate reasons for a DSO to enter into commercial agreements with generation and providers of demand services in order to provide network support or to manage network constraints (constraining on and constraining off as appropriate). For example, the active management of generation output by a DSO might enable a renewable generator to secure a faster, cheaper connection to the network in return for accepting a curtailment risk. This could be particularly attractive to an intermittent (wind or solar PV) generator where the resulting impact on annual load factor might be marginal.

Similarly, the use of electrical energy storage by a DSO in circumstances as described above would clearly be in consumers’ interests but, unless adequately distinguished, storage could be considered a form of generation (i.e. when exporting energy). Again, the important distinction is not in respect of the function (generation and supply) but in the markets which a DSO may and may not legitimately participate in. We note that the consultation accepts the use of storage for ‘grid-oriented services’ but we disagree with the statement that storage cannot be a substitute for fully available distribution lines, and used only to solve network constraints on a temporary basis. Provided the energy storage device is of sufficient power and energy capacity, there is no legitimate reason why the device should not be used as an alternative to reinforcement of network lines in order to provide the requisite level of security (e.g. N-1) during typical daily peak demand periods. Indeed, in a protected environment and under the direct control of the DSO, an energy storage device might be more reliable than network lines subject to potential 3rd party interference and/or severe weather.

Overall, the proposed framework is too prescriptive and reflective of a traditional passive role for DSOs rather than the future more active facilitation role that DSOs must adopt if the overall efficiency of electricity system is to achieve its maximum potential. The further implicit assumption is that DSOs will continue to have sole discretion over the way in which the local distribution system is managed. Given the rise of Smart Cities and the example of Berlin, it is likely that others may have designs on the way that local infrastructure can be managed efficiently.

5. For activities falling in category II and III (see Figure 1), under which regulatory conditions could DSO intervention be allowed?

A particular example we would highlight is where a DSO might enter into commercial arrangements to procure demand side response services from consumers (directly or through a commercial aggregator) as an alternative to undertaking network reinforcement which would otherwise be necessary to maintain specified levels of design security. Such services might also have a value as a reserve service to the Transmission System Operator, for example short-term operating reserve. Similarly, a DSO might install an electrical energy
storage device either to normalise power flows where local intermittent generation creates significant power swings or again, as an alternative to conventional network reinforcement. Again, there might be opportunities for a DSO to utilise such a device to enter into commercial arrangements to provide transmission system services, such as fast reserve and dynamic or fast frequency response.

It will be important to ensure that in pursuit of the objective of ensuring ‘neutrality’, regulation does not preclude the possibility of DSO’s making an important contribution to the efficient management of the wider electricity system through appropriate commercial arrangements with consumers, commercial aggregators and the Transmission System Operator.

In summary, we agree that a rationale and framework must be established that protects consumers while encouraging DSOs to be innovative in providing new services in conjunction (or in competition with) new market entrants.

6. Do you agree with the assessment of DSO access to data and data management?

In GB, the principle which has been established is that DSOs should have access to half-hourly consumption data from the smart metering system subject to:

- The data being sufficiently anonymised, partly through aggregation (e.g. to ascertain the loading on a discrete section of the network); and
- The DSO being able to demonstrate that their data management systems and procedures assure sufficient protection of data privacy.

Other data critical to the efficient management of low voltage networks includes: maximum demand; half-hourly rms voltage; voltage sag and swell alerts; and power outage alerts. Such data will become particularly important as penetration levels of low carbon technologies such as micro-generation, electric vehicle chargers and heat pumps begin to fundamentally impact power flows (magnitude and direction) and voltage (amplitude and quality) on low voltage networks where monitoring is currently minimal.

The overall challenge for DSOs will be to process the massive increase in data (both real time and time series) from multiple sources that will be required to manage a truly smart grid whilst ensuring robust provisions for assurance of data privacy and security, including security against cyber attacks.

In terms of overall data management it follows that data of adequate quality and timeliness will need to be accessible to those with a legitimate interest, and subject to appropriate overall control over privacy and security. Moreover, since there are likely to be many data hubs in future, it will be necessary to think beyond the concept of a traditional central management paradigm.
7. Do you agree that the risk of DSOs participating in some of the “grey areas” (particularly flexibility and DSR) decreases the more separated a DSO’s operational activities are from other competitive activities carried out by other companies within the same vertically integrated group?

“Grey areas” as defined in page 11 of the consultation document:
- Category II. Activity allowed under conditions (no potential competition)
- Category III. Activity allowed under conditions (potential competition, but special reason justifying DSO participation)
- Category IV. Activity not allowed (potential competition and no special reason justifying DSO participation).

We agree that robust business separation between a company’s distribution activities and any generation, wholesale or retail activities should reduce concerns over potential cross subsidy and/or market manipulation. However, the required distinction is not between ‘competitive’ and ‘non-competitive’ activities per se; it is between a company’s licensed distribution, and any licensed generation or supply, activities that the separation is required.

However, in that regard, some of the ‘grey’ areas will need to be close to the DSOs’ future operational activities (as outlined in our responses above). Transparency, audit and appropriate regulatory oversight (rather than vertical disintegration or the erection of unnecessary ‘Chinese walls’) should be used to protect consumers’ interests.

8. Do you agree with first considerations on the de-minimis threshold?

In terms of business separation, we are not persuaded of the merits of de-minimis thresholds. In GB, all DSOs, and indeed all but one of the 14 publically licensed networks they manage, serve over 1 million consumers. Moreover, the market in GB is fully unbundled which precludes even smaller IDNOs (who do not have prescribed geographic boundaries to their licensed activities) from participating in energy markets. In terms of business separation we would advocate the GB model being replicated across Europe but taking account of our comments under 3 above in terms of activities that future DSOs might legitimately undertake in the wider interests of consumers.

In terms of facilitating community energy projects, it might be that smaller local DSOs could be a catalyst. However, whilst recognising the importance of protecting consumers against the risks of market manipulation, this must not be at the expense of permitting DSOs, irrespective of the size of their consumer base, to explore innovative business opportunities which will benefit consumers.

Chapter 2

9a. Do you consider all the activities and topics described in this Chapter relevant to further defining a regulatory framework for DSO-TSO relationship and responsibilities?

As outlined in our answers to a number of questions above, we broadly agree that the developments described in chapter 2 are relevant, particularly in GB
where every DSO has responsibility for networks directly connected to the transmission system (which is operated at 400 or 275kV in England and Wales and at 132kV in Scotland) and where low carbon technologies such as electric vehicles and heat pumps are anticipated to make a major contribution to electrification of personal transport and home heating, and wind and solar PV is expected to make a major contribution to decarbonisation of electricity production. A significant proportion of (onshore) wind and virtually all solar PV generation will be connected to DSO’s networks. Overall, these developments are expected to give rise to new challenges for DSOs including:

- voltage management challenges due to reverse power flows, particularly on low voltage networks but extending to high voltage and even extra high voltage networks under some conditions;
- protection integrity (particularly schemes based on directional overcurrent protection);
- thermal rating challenges due to increased peak demands and changing demand patterns driven by intermittent generation and new Time of Use energy tariffs;
- power quality issues arising from increased use of power converters; and
- data management challenges arising from the need to fully leverage the opportunities arising from smart metering and network monitoring devices.

Future challenges to the secure and stable operation of the GB AC synchronous system have been outlined in National Grid’s System Operability Framework. These include:

- reduced levels of system inertia, particularly during periods of high wind and solar PV output and low demand, (leading to increasing rates of change of frequency following a sudden loss of a major infeed and concerns over the stability of DG);
- reduced system fault levels under similar conditions (leading potentially to voltage quality and protection co-ordination issues);
- reducing reactive demand at times of low demand (increasing P/Q ratio leading to voltage management issues);
- potential commutation issues for conventional current source converters associated with DC interconnectors;
- short-term forecasting challenges associated with intermittent forms of generation;
- increased requirements for balancing and reserve services to enable efficient system balancing; and
- the need to ensure the adequacy of black start provisions.

9b Are any activities or topics missing in the DSO-TSO relationship discussion?

Taken together, the challenges we describe above require that the System Operator, TNOs and DSOs work in unison to secure the most efficient operation of the whole electricity system while assuring continued security of supply. It follows that a coordinated approach to securing network support, reserve, and balancing services is essential. Ensuring robust arrangements for data exchange
and processing in both operational and planning timescales is a key challenge for all parties.

Regulation, in turn, must ensure that licence obligations and incentives are aligned, and that all parties are incentivised to secure the most efficient solutions from a whole system perspective, even where that results in one party incurring costs that delivers benefits to a different part of the system.

All of this must be balanced with the behaviour of the system users who may be either energy aware and/or pro-actively managing their energy portfolio (electricity, gas, heat, transportation, etc.) or be ambivalent and not engaged in their energy use, even when lucrative incentives are used. Either can act in a manner that is not efficient for the grid but is efficient for them personally. There is a need for a wider consideration of how the system as a whole can best be configured rather than just the regulated sector.

In order to ensure the requisite coordination and system integration, we see merit in establishing a System Architect function, initially in respect of the electricity system but ultimately with a whole energy system remit. This concept is not limited to the regulated activities of TSOs and DSOs but extends to multi-vector opportunities for energy optimisation and consumer/societal benefits.

10. Do you agree with the description of the activities and topics in this Chapter? If not, what is your view on your specific activity or topic that is relevant for the DSO- TSO relationship?

Overall, we agree with the activities and topics discussed in chapter 2 but we would also highlight the challenges outlines in our response to question 9 which provide important context for these activities.

We would also emphasise the importance of the need for better co-ordination between TSOs and DSOs in terms of determining optimum network development plans and operating policies where there is the potential to address each other’s issues rather than the individual issues of each party. A current example in GB is an emerging problem with overnight voltage rise on the transmission system due to reactive gain on the distribution networks at times of low demand coupled with an on-going improvement in demand power factor (i.e. an increasing P/Q ratio). An alternative to the TSO installing reactive compensation and/or switching out transmission networks to reduce reactive gain (and hence reducing system security of supply) could be for DSOs to switch out lightly-loaded HV circuits overnight (which might also reduce losses as a result of de-energising lightly loaded transformers) or adopt more active voltage management strategies.

However, the separate consideration of business plans by the regulator, coupled with separate regulatory determinations for TSOs and DSOs (covering different price control periods) may not be conducive to each party seeking the most efficient solution from a whole system perspective, particularly in the absence of explicit incentives on either party to seek whole system solutions.
A further ‘activity’ that is now of critical importance in GB is that of dissemination of lessons learned from a wide range of innovation trials carried out over the last decade under a number of innovation incentive mechanisms and research funding. The full assimilation of new technologies and innovative commercial arrangements by DSOs, TNOs and the SO requires a comprehensive knowledge transfer strategy to ensure that new techniques become fully embedded as ‘business as usual’.

Overall there is a need for fresh thinking in future energy system complexity with full consideration of how whole energy system integration and holistic architecture will be ensured.

11. Do you agree with the statement that further regulatory guidelines may be required (in addition to current Network Codes) and if so, which regulatory guidelines do you consider necessary?

Based on work undertaken by the Institution of Engineering and Technology (IET) over the last two years under its Power Networks Joint Vision initiative, we believe that a number of important changes to the overall governance of the electricity system are now essential. These might ultimately take the form of new regulatory guidelines and Network Codes but the overriding need is that of electricity system integration which in turn requires the development of a ‘system architecture’ designed to address the challenges we have outlined above.

As we comment under our response to question 9 above, we envisage the establishment of a System Architect to oversee the new system architecture and system integration challenge. Whilst new regulatory guidelines and Network Codes might well be an outcome of this new oversight, the institutional framework for the System Architect has yet to be determined. However, in a future more complex world characterised by rapid and disruptive change, it will be important for the regulatory framework to be sufficiently agile to respond speedily and effectively to technical and commercial innovation and not become a barrier. Failing to achieve this objective is likely to result in innovation being stifled from the outset, or promising products and services failing to reach commercialisation.

Chapter 3

12a. What, if any, are the particular or incremental risks attached to innovative and nonconventional investments?

An important provision is that the introduction of any new technology is carefully risk-managed through established best-practice asset management techniques suitably adapted to address the particular risks associated with unconventional solutions.

Techniques such as Failure Mode Effect Analysis need to reflect the potential failure modes and consequences of new technologies. The extent to which infant
mortality risk might apply to newly introduced technologies that have yet to be deployed at scale needs also to be considered.

A further consideration when simultaneously introducing a number of new technologies is whether there might be interdependent failure modes and/or unanticipated interactions giving rise to a heightened failure impact.

Our experience in Great Britain is that regulatory incentives are key to entrepreneurial DSO behaviour, including the acceptance of incremental risk.

We would also comment that there is no substitute for field trials and demonstration projects. Again our experience in GB (for example with a number of Low Carbon Network Fund projects) is that extensive consumer participation and feedback is an essential prerequisite to establishing a pathway for the scaling-up and full deployment of innovative new services and products.

In terms of risk, demonstration projects have highlighted new challenges for DSOs, for example:

- commitment of management time in developing concepts to form cost-benefit assessed deliverable project, creating and nurturing relationships, and maintaining momentum during the delivery phase;
- forming new relationships with vendors, academia, SMEs, consumers and other stakeholders requiring the establishment of partnerships with equitable sharing of risks and rewards rather than (or in conjunction with) traditional contractual relationships;
- the management of intellectual property such that a balance is achieved between incentivising innovative companies to develop new products and ensuring value is returned to consumers – for example through permitting background IP to be retained while requiring foreground IP to be shared;
- establishing successful innovation as business as usual which may require considerable staff training and knowledge transfer, adoption of new standards and business procedures, and appropriate risk management of any new technology not yet proven over time or at scale.

12b. Do these warrant special recognition by NRAs? To which extent, if any, is this incremental risk borne by DSOs?

It is important to remember that the electricity system extends beyond the meter to include the consumer’s ‘system’ which will play an increasingly important role in the future. The need for innovation is therefore not limited to technology, it will often also extend to commercial innovation, for example contracts with consumers for DSR, or with DG operators to provide services for network support or to manage constraints. At the domestic level, time of use (ToU) tariffs will provide incentives on consumers to manage their electricity consumption in a manner which supports overall system efficiency; we comment on ToU tariffs in our response to question 16.

It follows that a future DSO will become more reliant on customers (consumers, prosumers and generators) for the management of their networks. The reliance which a DSO can place on customers to provide support services (potentially on
demand) is an area which requires further research and field trials. However, results from innovation projects undertaken in Great Britain suggest that such services can be a cost-effective alternative to conventional network investment provided the reliability of such services is factored into the overall risk assessment. What remains, is the need to develop evidence-based reliability metrics to enable the risk of reliance on such services to be compared with the well-established reliability metrics associated with traditional network assets.

Traditional regulatory frameworks might unintentionally reward DSOs that are risk averse and prefer to adopt the ‘safe’ alternative of traditional investment which in most cases will address new challenges in the shorter term, and possibly at lower cost, but at the expense of longer term efficiency gains. Future regulatory frameworks must therefore incentivise solutions whereby network service reliability has some dependency on customer behaviour, where this can be demonstrated to provide an economic alternative to conventional network investment.

13. Does the conventional focus on rate of return regulation on capital expenditure, and in some cases limited pass through of OPEX, have the effect of discouraging certain smart grid investments? What alternative approaches help incentivise DSOs to adopt smart grids?

We believe that appropriate incentives are an essential enabler of innovation for DSOs whose financial risk portfolio is designed to be low in order to secure low costs of capital and hence affordable distribution use of system charges. We would cite the GB example where Ofgem has, over the last decade, introduced a number of complementary innovation incentives including:

- The Innovation Funding Incentive (IFI);
- Registered Power Zones (RPZ);
- Low Carbon Network Fund (LCNF); and
- Network Innovation Allowance and Competition (NIA/NIC)

These mechanisms share a common principle, which is that up to 80% (IFI) and 90% (LCNF and NIA/NIC) of funding can be recovered by the DSO through distribution use of system charges. These mechanisms have been highly successful in promoting innovation, including through competitive bidding for funding which ensures only high quality projects are funded.

The expectation is that consumers’ contributions will be (at least) fully returned to consumers in the following regulatory period in the form of more efficient network investment.

Overall, there needs to be a balance of risk between shareholders and consumers. We believe the above mentioned innovation incentives, coupled with the totex incentive mechanism referred to in our response to question 14 below (which shares efficiency gains between shareholders and consumers), provides a sound basis for encouraging innovation and ensuring an appropriate sharing of risk. This might be particularly important as many of the new areas of expenditure might fall under the traditional definition of opex rather than capex.
(for example renewable-term DSR contracts as an alternative to major system reinforcement).

14. CEER would welcome views from stakeholders on the pros and cons of output-based incentives. Please also define for which regulatory incentives they might be appropriate.

We believe that output-based incentives are an essential component of efficient regulation provided that the outputs represent what consumers want whilst also ensuring the long-term integrity of the distribution system.

It follows that incentives must support investment options that are considered on the basis of long-run cost-benefit analysis, and not necessarily options which will deliver faster benefits (e.g. within a price control review period) but not the greatest benefits in npv terms.

In terms of output-based incentives which might be appropriate, under the RIIO mechanism, GB DSOs are subject to:

- Rewards and penalties relating to quality of supply performance against prescribed targets (number and duration of customer interruptions);
- Rewards and penalties relating to customer service (based on customer level of satisfaction as captured by independent surveys);
- Target performance levels for providing quotations for requested new network connections, and subsequently for making connections;
- Targets relating to the utilisation and health of their network assets (so called load and health indices); and
- A totex incentive mechanism which encourages DSOs to outperform regulatory allowances through innovation (any resulting cost savings are shared between shareholders and consumers).

15. Do you agree that to allow timely recovery of DSO revenues, assumptions on consumption patterns in tariff models could be updated within price control periods?

In GB, DSOs' base revenues (not prices per se) are determined by the price control review. It follows that DSOs are not subject to volume risk (i.e. units distributed). Their tariff price structure reflects the allowed revenue returns and any under or over recovery in any year is corrected by adjustments to prices over the following year.

As explained above, GB DSOs base revenues are subject to adjustments according to their performance against the output incentives. Such adjustments are accommodated through the tariff price structure.

16. How can ToU network tariffs be coordinated with system energy prices?

The only practical way of applying distribution time-of-use (ToU) charges is through the energy tariffs offered by Suppliers. It follows that Suppliers’ energy
tariffs would need to be ToU based and hence would be dependent on the availability of a smart metering system able to capture periodic (typically half-hourly) data.

In order for Suppliers to be incentivised to introduce ToU pricing at scale, there is a need for settlement to be based on actual half-hourly (or similar) consumption and not profiled consumption. In GB, domestic and SME consumers’ energy consumption is subject to settlement based on 4 standard profiles. Whilst these profiles broadly reflect typical consumption patterns, it will be apparent that micro-generation, EV charging and heat pumps will increasingly render such standard profiles obsolete and not fit for purpose.

A further challenge is that energy based ToU pricing will logically more closely reflect real-time energy production prices which, with high volumes of low marginal cost, but intermittent, generation, will vary significantly depending on climatic conditions. Moreover, ToU energy price signals based on marginal costs of production are likely to dominate network marginal cost based price signals. It follows that energy ToU prices might become dynamic in nature reflecting marginal production costs rather than based simply on demand profiles. In conclusion, ToU pricing might not always encourage consumers to avoid peak demand periods, and so might not be entirely effective in reducing the need for network investment.

The ultimate objective is that price signals are broadly reflective of marginal costs, whether these costs relate to distribution or transmission networks reinforcement, or the short run marginal cost of generation. That is not to say that consumers should be exposed to the full impact of energy spot price volatility but our experience in GB with a number of innovation projects is that well designed and communicated tariffs incorporating appropriately weighted price signals can be effective in encouraging energy management, and can actually be welcomed by consumers. Please note however our comments under 17 below.

17. Are there circumstances under which suppliers should be required to pass through the distribution tariff signal to customers? If so, should there be regulation to ensure this happens?

In the absence of a specific Supply licence condition, it is likely that Suppliers would see little benefit in passing through distribution price signals. It should be noted however, that the distribution component of a typical domestic or SME tariff will be a small component of the overall energy charges, and in relative terms is likely to become an even smaller component as electricity tariffs increasingly reflect the cost of decarbonising electricity production.

18. Do you agree with the above assessment of different cases when DSOs or other parties should have contracts or agreements with consumers and distributed generators?
We would refer to our responses to questions under Chapter 1 above which outlines the nature of contracts and agreements between DSOs and consumers (either directly or through third parties) which we believe are appropriate. With regard to table 2:

- DSR through static or dynamic tariffs are appropriate means by which DSOs can interact with consumers through the consumer’s Supplier (subject to our comments under 16 above);
- DSR ‘dispatch’ contracts with industrial and commercial consumers can be an effective means to manage temporary network constraints (for example network outages at times of peak demand); and
- Constraining-on or curtailment contracts with DG operators can be effective in (respectively) providing network security support and managing connection costs for intermittent generation.

For DSR contracts with industrial and commercial consumers, there might be benefits in arranging these through commercial aggregators who may be able to leverage value by using the DSR capability to also provide reserve services to the System Operator. However, that should not preclude a future DSO contracting with the System Operator directly.

19. Which type of regulatory controls should be adopted by NRAs for DSOs, in cases of contractual arrangements falling under categories II and III?

We do not see a need for strong regulatory controls other than that ensuring that contracts do not infringe appropriate business separation requirements or disrupt the energy market. Rather than unnecessarily prescriptive regulation which might have the effect of stifling innovation in contractual arrangements, the emphasis should be on incentives. A further important consideration is that simplicity is important where the arrangements interact with third parties and consumers.