A successor to ER P2/6: existing issues and lessons from "Flexible Networks for a Low Carbon Future"

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Executive summary and learning points

This note is concerned with a network's ability to meet demand for power. In other words, with 'security of supply' and, in particular, with standards or conventions that drive a distribution network planner's decisions in respect of ensuring that demand will be met in future. It takes lessons from the "Flexible Networks" Low Carbon Networks Fund project in respect of 'flexible' network actions such as dynamic or real-time ratings, network reconfiguration and voltage regulation along with learning from network monitoring, not least to aid better forecasting of demand, and applies them in respect of possible development of a successor to the main standard that drives network investment to provide adequate reliability of supply to distribution connected demand, Engineering Recommendation (ER) P2/6, i.e. the 6th edition of ER P2.

This note discusses a number of issues in respect of ER P2/6, its application by Distribution Network Operators (DNOs) and its interactions with other regulatory initiatives, not least the Interruption Incentive Scheme (IIS) and 'load indices'.

Learning points

The main learning points are:

1. Flexible network interventions such as dynamic or real-time ratings, network reconfiguration and voltage regulation, suitably applied, can provide network capacity headroom.
2. Network reconfiguration to transfer demand between groups can aid the meeting of demand provided network capacity headroom is available in the neighbouring group to which demand is transferred at the time at which the transfer is enacted.
3. Monitoring of network loading and application of suitable statistics can improve the forecasting of demand.
4. Exceedance of a 'circuit capacity' does not necessarily mean that that circuit will trip with the consequence of interrupting demand, or that ageing of assets on the circuit will be significantly accelerated with the result of either early asset write-off or higher probability of trip.
5. There is inconsistency among DNOs in respect of forecasting of group demand and definition of 'circuit capacity'.
6. While ER P2/6 seemingly does not prevent the use of flexible network interventions, it is seemingly not yet habitual among all DNO planners to explore them and test whether they are the most economic and efficient means of meeting the criteria set down in ER P2/6 in respect of meeting demand.

7. There are inconsistencies between three regulatory initiatives in respect of DNO investment to meet demand: ER P2/6, the IIS and 'load indices'.

Recommendations

1. Work recently initiated by a Working Group of the Distribution Code Review Panel to review ER P2/6 with a view to making recommendations on a successor standard is welcome and is recommended to address 'risk' and different means by which demand might be met, including through use of flexible network interventions such as dynamic or real-time ratings, network reconfiguration and voltage regulation, and means not explored by the Flexible Networks project such as demand side response.
2. The presentation of any new distribution network design standard should be carefully considered and should learn lessons from other standards, not least the National Electricity Transmission System Security and Quality of Supply Standard (NETS SQSS), in respect of clear and consistent definitions of terms, secured events and system conditions to be avoided.
3. Any new distribution network design standard should give clear and credible guidance on the background conditions against which network capacity is to be assessed, including both levels of demand and operation of generation plus how storage and flexible demand might be treated.
4. In order to allow its application by a DNO against a potentially rapidly changing background of both demand and generation technologies and new connections, any a new distribution network design standard may need to be formulated in such a way as to be easy to interpret and apply even if that means that the outcome of application cannot be guaranteed to always be completely optimal.
5. There should be consistency among standards, conventions and incentives such that DNO behaviours are driven unambiguously towards their customers' best interests *and* DNOs can be confident of recovering their reasonably incurred costs. It is recommended that the interactions between ER P2/6, the IIS and 'load indices' are reviewed. In addition, it is recommended that work is undertaken to develop standards that drive both DNOs and generators towards economic and efficient accommodation of generation on distribution networks.

Contents

1 Introduction

This note is concerned with a network's ability to meet demand for power. In other words, with 'security of supply' and, in particular, with standards or conventions that drive a distribution network planner's decisions in respect of ensuring that demand will be met in future. As such, a key document for distribution network operators (DNOs) in Britain is Engineering Recommendation P2/6 (ER P2/6), which is discussed both in terms of what it says and how it is used. The latter is addressed in light of learning, in particular, from the "Flexible Networks" Low Carbon Networks Fund project led by SP Energy Networks. A number of recommendations are made in respect of a successor document to ER P2/6 that can drive network development to meet demand.

The remainder of this section introduces ER P2/6, the "Flexible Networks" project and the purpose of this discussion. Subsequent sections outline publicly acknowledged issues with ER P2/6, issues that have become apparent to participants in the "Flexible Networks" project in the course of that project and regulatory influences on distribution network development in Britain before finally presenting a number of recommendations.

1.1 Engineering Recommendation P2/6

Engineering recommendation (ER) P2/6 is the 6th revision of ER P2 which is concerned with "security of supply" and is described in its introduction as a "guide to system planning". Distribution Network Operators (DNOs) in Britain are obliged under their operating licences to comply with the Distribution Code. The Distribution Code refers to P2/6 as follows:

> In accordance with the Condition 5 of the Distribution Licence, DNOs shall plan and develop their DNO's Distribution Systems to a standard not less than that set out in DGD Annex 1 Item 4, Engineering Recommendation P2/6 – "Security of Supply" or such other standard of planning as DNOs may, with the approval of the Authority, adopt from time to time.

ER P2/6 "sets out the normal levels of security required for distribution networks classified in ranges of Group Demand". The capacity to meet demand is defined for a group for which the connection has been depleted by one or two circuit outages as:

a. "The appropriate cyclic rating of the remaining transmission or distribution Circuits which normally supply the Group Demand, following outage of the most critical Circuit (or Circuits); plus
b. "Transfer Capacity which can be made available from alternative sources; plus
c. "For demand groups containing Distributed Generation (DG), the effective contribution of the DG to network capacity."

1.2 The "Flexible Networks" Low Carbon Networks Fund project

The "Flexible Networks" Low Carbon Networks Fund Tier 2 project led by SP Energy Networks has largely been concerned with identifying and utilising existing capacity on distribution networks that current, conventional ways of planning and operating them would not normally recognise. This is primarily motivated not by avoidance of network expansion or reinforcement but by buying time until the extent of growth of demand associated with decarbonisation, e.g. more electric heating or charging of electric vehicles, becomes apparent and hence there can be more confidence in a need for reinforcement. The methods explored include the following:

- making use of 'dynamic' or 'real-time' thermal ratings on, in particular, transformers and overhead lines;
- identifying a default network configuration that minimises expected values for customer interruptions and customer minutes lost but can be reconfigured in the event of an outage to exploit available network thermal capacity and voltage 'headroom' and 'footroom' when supplying the maximum amount of load;
- providing voltage regulation where cost-effective to do so as a means of avoiding breach of voltage limits being a constraint on use of available thermal network capacity headroom.

The above depend on the following:

- knowing the time series profile of demand, e.g. in the course of a day, in order that transformer or overhead line conductor temperature rises can be predicted and excessive hotspot temperatures or line sags can be avoided;
- knowing the split of demand on different secondaries connected to a primary in order that, for example, voltage rise or fall issues can be identified;
- knowing how many customers are connected to each secondary;
- limiting circuit ratings to the thermal rating of the critical section of a circuit or the circuit's protection rating, whichever is lower, or adapting the protection settings to be coherent with the prevailing thermal rating;
- ensuring that switching sequences to reconfigure the network do not disconnect demand temporarily, do not inadvertently trigger operation of protection and can be implemented safely and quickly.

Furthermore,

- information gathered in the course of characterising demand can be used to provide better long-term demand forecasts for network planners;
- in order that it can be accurately and realistically determined whether network capacity is sufficient for future operating conditions, it should be possible for planners to anticipate or model the way a network would be operated when dynamic ratings, voltage regulation and network reconfiguration are all being fully utilised;
- operators should have access to reliable and easy to use advice on the need for network reconfiguration for demand to be met in the short-term, minimising expected CI and CML where possible, utilising dynamic ratings and voltage regulation, and being advised on suitable switching sequences in cases where reconfiguration is necessary.

1.3 The purpose of this discussion

A number of possible issues with the text of ER P2/6 and its interpretation have been discussed among GB network utilities and in industry working groups since the introduction of P2/6 in 2004. The work conducted in the "Flexible Networks" project is in a position to add to that discussion in some particular ways:

- to what extent does P2/6 permit the use of measures explored in "Flexible Networks" to free up network capacity or allow investments in primary assets[1] to be delayed until there can be certainty about their need; or
- to what extent does P2/6 prevent the use of measures explored in "Flexible Networks"?

This discussion addresses possible issues that might arise for a network planner when assessing compliance with ER P2/6. It also outlines some of the regulatory context around ER P2/6 and makes some recommendations for a distribution network design standard that can act as a successor to ER P2/6. In passing, it also comments briefly on the connection of generation within distribution networks.

2 Publicly noted possible issues with ER P2/6

2.1 Ofgem open letter, 2007

In an 'open letter' in December 2007, the Office for Gas and Electricity Markets in Britain, Ofgem, agreed that the distribution licensees should investigate whether changes to ER P2/6 might be required in respect of the following:

- **clarity of definitions of Group Demand and Transfer Capacity** – a report to be made by June 2008.
- in light of increasing off-peak loads, **redefinition of the loading conditions against which the system is to be designed** – a report to be made by June 2008.
- the account to be taken in the standard of the **length of construction outages** (no specific timescale set for reporting).

In addition, Ofgem noted other issues that, at that time, it felt were adequately addressed in current standards or licences:

- **the basis of the reliability calculations underpinning ER P2/6** – in the December 2007 'open letter', Ofgem gave no reason for deciding that the time and resources needed to do this were unjustified.
- **environmental and sustainability issues, in particular 'full lifecycle costs'** – Ofgem felt that the DNOs should already have sufficient clarity on the need to take full lifecycle costs (including, Ofgem added, "account of losses, cost of carbon and environmental/societal impacts") into account through the general licence condition giving a duty to develop and maintain an efficient, co-ordinated and economical system of electricity supply.
- **the effect of higher summer loadings and reduced plant ratings due to higher ambient temperatures** – Ofgem felt that this could be taken into account through the specification of ratings to be used when applying P2/6.
- **standards for connection of generation** – Ofgem felt that this should be left to bilateral arrangements between DNOs and generators or between DNOs and NGET where there is a transmission impact.

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[1] The term 'primary assets' is used here in the sense of "Heavy current equipment that carries power currents at voltages from LV up to and including 400kV", in contrast to 'secondary' equipment which is "Ancillary equipment used to protect, control or maintain the Primary plant". (See Engineering Recommendation G85).

A number of other issues were noted at that time by Ofgem but Ofgem declined to take a view on whether or not action was required:

- **the accommodation of demand side management and 'virtual power plants'** – Ofgem wanted to wait for various future network scenarios to be developed before deciding to take any action on this.
- **co-ordination between DNOs and transmission**. This concerns two aspects: planning (mainly, who has responsibility for ensuring compliance at grid supply points) and operation. As regards the latter, Ofgem decided that it was entirely outside the scope of P2/6 and that matters should be left to the Grid Code and Distribution Code Review Panels. For the former, while it was tacitly acknowledged to be pertinent to P2/6, again Ofgem preferred to wait and see what developed in relation to some then recent Grid Code proposals.
- **treatment of distributed generation in P2/6**. It was noted that, at the time, there was so little new DG that experience was absent on how the changes in its treatment introduced into P2/6 were playing out. However, Ofgem did promise to ensure that "current and future price control incentives for distributed generation, the further development of the DNOs' charging methodologies and the development of Engineering Recommendations G75 and G59 all support the growth of distributed generation".

2.2 Distribution Code Review Panel ER P2 Working Group

On its website, the Distribution Code Review Panel (DCRP) notes that[2]

> P2/6 (i.e. the present version of P2) was introduced in July 2006; however its basic content is largely unchanged from P2/5 which was introduced in October 1978.
>
> Society and the industry have changed substantially since 1978 and it is timely to review P2, to determine if there is a need for such a standard, and if so what form a modern standard should take.

The DCRP conducted a short consultation in late 2012/early 2013 asking for views on whether such a review should be undertaken and, in 2013, the Energy Networks Association (ENA), on behalf of the DNOs, issued an invitation to tender for work to review ER P2/6. A (DCRP) working group (WG) was established to manage the work, the scope of which is described on the WG's website[3] as

1. Review the perceived deficiencies of the current arrangements
2. Consider what is required of a future security standard
3. Evaluate potential options achieving desired security arrangements
4. Evaluate implications of the options
5. Recognize the impact of changes in technology
6. Recognize the impact of changes in customer behaviour
7. Recognize the impact of smart grids
8. Recognize the impact of EU Network codes

[2] See http://www.dcode.org.uk/dcrp-er-p2-working-group.html
[3] http://www.dcode.org.uk/dcrp-er-p2-working-group.html

Although phase 1 the work was originally expected to be completed in summer 2014, it is understood to be beginning only in spring 2015. In a meeting of the WG in January 2015, the following issues were described as having changed since the invitation to tender was first issued:

1. LCNF is now 18 months further on and a number of relevant projects are now complete or due to report e.g. Electricity North West's C2C project and DSR related projects in general.
2. Demand side response is now under consideration; it may not be a key driver but should be considered during the evaluation.
3. From 1 April the new RIIO ED1 price control period commences with a new interruption incentive scheme (IIS) including incentive rates and caps etc.
4. The Smart Grid Forum WS 7 project deep dive on LCNF network solutions out to 2030 could have an impact on security requirements and the Consortium needs to engage with the WS7 activity, the outputs from which are expected during spring summer 2015.
5. Losses have been raised as a key issue by Ofgem, driven by EU directives.
6. Any issues relating to supply security in the latest ENTSO-E 10 year plan should be considered for potential impact on the P2 review.
7. Should the new standard consider demand only as opposed to capacity since consumers are and will increasingly become "prosumers" (producers of and consumers of electricity)? There is a link in this to the SQSS which differentiates between generators and demand customers.

3 Issues identified by participants in the "Flexible Networks" project

3.1 Engineering consequences of *apparent* non-compliance with ER P2/6

One thing that the "Flexible Networks" project has sought to highlight is that, if conventional capacity on primary assets does not appear to meet, in full, future peak demand either in winter or when there is a planned outage, it is not necessarily a disaster. The project reaches that conclusion for a number of reasons:

1. What conventional methods *suggest* will be the winter peak demand or highest demand when there is a planned outage has a good chance of *not* being the demand.
2. Loading on a primary asset in excess of its continuous or even its cyclic rating does not necessarily mean that the critical temperature of that asset's conductor or insulation will be reached.
3. Loading a primary asset in excess of its continuous or cyclic rating does not necessarily mean that it will be prematurely aged to such an extent that significant early asset write-off or significant unreliability result.
4. Loading a primary asset in excess of its continuous or cyclic rating does not necessarily mean that protection will operate to disconnect the asset and, as a consequence, disconnect demand.

Furthermore, although not explored in this project, temporary reduction of demand (by suitable contractual means to compensate affected electricity users, some of which have been explored in other LCNF projects) may well be a more cost-effective means of meeting demand than expenditure on additional primary assets.

The project has shown that

1. some simple methods can be used to provide better forecasts of peak demands;
2. significant capacity 'headroom' can be released by using dynamic ratings that take account (a) of ambient conditions and (b) thermal inertia whereby an increase in loading on an asset does not instantaneously lead to its temperature reaching a critical level;
3. based on established IEC, IEEE and CIGRE standards, the acceleration of ageing of a transformer associated with loading it above its continuous rating to meet the demand profile on high demand days is negligible.

For a network planner, however, there remains the chance that what they think will be future operating conditions will not be the actual conditions. In other words, there will be some risk:

1. that demand cannot be fully met;
2. that there will be over-investment in network assets.

3.2 Risk and its nature

In mathematical terms, risk concerns both the probability of an adverse situation arising and the extent of the adversity. For example, in respect of the latter element, disconnection of 100MW of demand would be worse than disconnection of 10MW even though both are undesirable.

If system design or operation standards were concerned with risk, they would be based on both the probability of an adverse situation arising and the extent of adversity of that situation. A threshold of maximum acceptable risk might be defined in which, for example, a low probability of a small impact might be tolerated but not a low probability of a large impact or a high probability of a small impact. Some recognition of this is implied in ER P2/6 since some events leading to disconnection of small amounts of demand are tolerated; in addition, large amounts of disconnected demand are required to be restored more quickly than small amounts.

It might be argued that risk aversion on the part of DNOs or regulators that have approved particular standards – specifically, what is stipulated in ER P2/6 – has led to 'security of supply' being addressed in terms of instantaneous peak demand and the need for sufficient network capacity to meet that demand, with the implication that that there is zero probability of all of that demand being disconnected. However, such an argument would be wrong, and not only because the highest level of security is specified only for the largest demand group. This is due to the following reasons.

1. **What is the probability of outages arising?** P2/6 says that it should be possible to meet peak demand only under a 'first circuit outage' condition. However, although the probability of even a circuit outage coinciding with peak demand is low, it is *possible* for there to be more than one circuit outage at the time of peak demand in which case it may be expected that the remaining circuits will have insufficient 'circuit capacity' to satisfy the demand.
2. **What happens if there is a shortfall of 'circuit capacity'?** If demand does exceed total available 'circuit capacity', the implication is that each overloaded circuit would trip thus entirely disconnecting demand. However, in practice, disconnection depends on the action of protection. Overcurrent protection is commonly used on distribution circuits and the trip action depends on the extent of overload and its duration. It is entirely possible for the 'circuit capacity' to be exceeded and the circuit *not* to trip.

3. **What is a 'circuit capacity' anyway?** In respect of underground cables, continuous and cyclic ratings are both widely recognised, the latter defined in accordance with Engineering Recommendation P17 and based on the idea that, typically for 6 hours, the loading might be above the continuous rating provided it is reduced below a certain level for the other 18 hours in a 24 hour cycle. For transformers, continuous and cyclic ratings are defined but also 'emergency ratings'. For overhead lines, Engineering Recommendation P27 defines ratings based on certain probabilities of temperatures being exceeded given the variation of ambient conditions. In respect of all 'static', i.e. unchanging (not 'dynamic' or 'real time') ratings, when calculating them, assumptions are made about ambient conditions that are normally conservative but might, under circumstances, be optimistic hence entailing a risk of exceedance of a safe loading level.
4. **What is the contribution of generation within a distribution demand group, i.e. 'distributed generation' (DG)?** Output from any generator is uncertain because of the possibility of forced or maintenance outages, varying patterns of use of the generator by its owner and varying availability of power from renewables. The contribution of DG to meeting demand is therefore uncertain. Assumptions on contributions are outlined in ER P2/6 but based to a large extent on sparse data.

4 Regulatory influences on distribution network development

There are currently a number of regulations or regulatory initiatives that influence DNO network planning and development. The main ones are:

1. The Distribution Code, in particular the requirement to comply with ER P2/6;
2. the Interruption Incentive Scheme (IIS);
3. the RIIO-ED1 price control framework, in particular the link to load indices.

Some issues associated with current practice in application of ER P2/6 are discussed below followed by brief descriptions of the IIS and load indices.

4.1 Application of P2/6: current practice

ER P2/6 and its predecessors have long been regarded by DNOs as fundamental in determining the need or otherwise for load-related capital expenditure to increase the power transfer capability of their networks. In relation to the main concepts explored within the "Flexible Networks" project – dynamic and short-term ratings, improved voltage regulation, better demand forecasting and network reconfiguration – there are arguably three key aspects of ER P2/6 that would determine whether those concepts can be used, are prohibited or are obliged. They are discussed briefly in turn below and are:

1. the definition of 'circuit capacity';
2. the quantification of 'group demand'; and
3. the extent to which transfer of demand between groups is used.

4.1.1 Definition of 'circuit capacity'

Based on the author's conversations with a number of network planners from a few DNOs, it seems that

- cyclic ratings are used as a matter of course when defining 'circuit capacity'.
- when cyclic ratings are used, the daily profile of load is not always checked below 132kV.
- emergency ratings are used in respect of circuit capacity only when assessing second circuit outage (N-2) conditions, and then only for existing groups and not new connections.
- when emergency ratings are used, possible acceleration of ageing is typically not taken into account[4].
- summer ratings are used when assessing N-2 conditions.
- short term ratings other than cyclic ratings are not used.
- the expected variations of real-time ratings are not usually considered.
- voltages as limiting factors in the transfer of power are typically only considered in respect of 132kV or 33kV[5].

The planners consulted by the author believe that ER P2/6 as currently written allows them to use dynamic or real-time ratings, and some planners make use of that scope but not all. For the practice to become more widespread, they see a need for appropriate guidance (which one DNO already has) and learning, training and monitoring.

From time to time, utilisation of dynamic ratings might require changes to protection settings; some engineers regard that as acceptable while others do not, primarily on the grounds that any change of settings always gives an opportunity to get the settings wrong. In other words, in the latter case, existing protection settings would set an upper limit on dynamic ratings.

The planners consulted judge that accelerated ageing can be considered and would be accepted if (i) it allows demand to be met and (ii) the early asset write-off cost is lower than the cost of an alternative means of allowing the demand to be met. However, they did not all agree that use of short-term real-time ratings would be reasonable, one planner regarding it as a "step too far".

4.1.2 Definition of group demand

Group demand is defined in P2/6 as follows:

> *Group Demand (multiple sites)*
>
> The sum of the appropriate estimated maximum demands in the adopted load estimates with allowance for diversity appropriate to the group, or the DNO's own estimates for those parts of the system for which no load estimates have been adopted.
>
> *Group Demand (single site)*
>
> The appropriate estimated maximum demand given in the adopted load estimates or the Distribution Network Operator's (DNO) own estimates for those points for which no load estimates have been adopted.

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[4] A workshop on ER P2/6 led by Parson Brinckerhoff as part of the C2C LCNF project drew the comment from a network licensee attendee that "they felt more comfortable with overloading equipment at the higher voltage levels due to their better understanding of the thermal operation of such equipment."

[5] For example, voltage issues may trigger the need for a new primary transformer (33kV to 11kV) particularly in a rural group where the ability to support the load via 11kV back-feeds is limited not by thermal rating but by the voltage drop on a relatively long circuit. However, in such cases, use of reactive compensation or in-circuit voltage regulation should also be considered.

The Distribution Code requires that DNOs quantify 'average cold spell' (ACS) demand. Only one of the DNOs consulted by the author has an established process for applying weather correction to a measured demand in order to find its ACS equivalent.

There seem to be varying methods in how group demand is identified. However, a number of the planners consulted believed that there should be standard guidance on how future demand *might* be estimated, e.g. how to use historic outturns, how to take account of variability due to weather or how to take account of diversity among sub-groups, but not rules on how future demand *should* be estimated[6].

4.1.3 Transfer capability and transfer capacity

Transfer Capability and Transfer Capacity are defined in P2/6 as follows:

> *Transfer Capability*
>
> The extent to which transferable load and transferable capacity can be utilised or provided in the event of a system being affected by outages.
>
> *Transfer Capacity*
>
> That Circuit capacity from adjacent load groups which can be made available within the times stated for the First and Second Circuit Outages in Table 1.

The planners consulted by the author believe that it is obvious that the initial network configuration against which compliance with P2/6 is tested is that which maximises the demand that can be met for the given circuit ratings (and voltage limits). However, as is discussed briefly below, Ofgem's apparent definition of 'load indices' might mean that, in different stages of a business cycle, the demand that can be met is not maximised[7].

4.2 The Interruption Incentive Scheme

According to Ofgem[8],

> The interruption incentive scheme has symmetric annual rewards and penalties depending on each DNO's performance against their targets for the number of customers interrupted per 100 customers (CI) and the number of customer minutes lost (CML).
>
> The proportion of revenue exposed under the scheme is 1.2 per cent for CI and 1.8 per cent for CML.

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[6] A workshop on ER P2/6 led by Parson Brinckerhoff as part of the C2C LCNF project drew comments from network licensee attendees that "the vagueness of the wording permits flexibility when adopting an interpretation" but also that there was "uncertainty regarding the need for a derogation, e.g. for teleswitching". In respect of the same workshop, the following note was made: "A disadvantage of clarifying the definition of Group Demand was that it would no longer allow the existing vagueness to be exploited in other ways."

[7] The main business cycle relevant to regulated network licensees is arguably that related to the periodic price review conducted by Ofgem.

[8] See https://www.ofgem.gov.uk/electricity/distribution-networks/network-price-controls/quality-service/quality-service-incentives

Each DNO area has its own, area specific target that are said to take into account the geography of the area and the historic development of network there. (For example, those for the SP Manweb, Electricity North West and London/UKPN areas tend to be significantly lower than those for other areas). The most recent published CML and CI performance report relates to 2008/9. Over the 4 years leading up to April 2009, Ofgem reports that, under the IIS, the maximum reward was £30 million for SSE Southern and the maximum penalty was £12 million for CE YEDL. According to the 2008/9 report, the GB average number of interruptions per 100 customers per year was around 70 while the average number of minutes lost per customer per year was around 75.

4.3 Ofgem load indices

In a document published in March 2013 – "Strategy decision for the RIIO-ED1 electricity distribution price control: Reliability and safety" – Ofgem set out its final views on 'load indices'. According to Ofgem:

> One of the key factors in the overall reliability of a network is how often assets are loaded above their rated capacity. Networks that are overloaded will experience increased interruptions to customer supplies. This is because the physical condition of their individual assets will deteriorate at a faster rate than otherwise anticipated, leading to an increase in outages.

The above might be regarded as broadly true; however, as discussed above, 'overloading' (depending on how it is defined) does not necessarily lead to asset deterioration and deterioration at a faster rate than anticipated does not necessarily lead to an increase in outages.

Although Ofgem recognises that the Interruption Incentive Scheme (IIS) is designed to ensure an adequate level of reliability of supply to customers, Ofgem also argues that it is a lagging indicator and that assurance of adequate investment before significant unreliability requires an additional indicator. This, for Ofgem, is represented by load indices for supplies to 11kV substations (primaries). Based on advice from a Reliability and Safety Working Group (RSWG), the indices are calculated in terms of 'maximum demand' expressed as a percentage of circuit capacity and 'duration factors' which are related to the number of hours in a year for which the 'maximum demand' exceeds the circuit capacity. 'Maximum demand' is defined in terms of 'latent demand' and the contribution from connected generation. However, what counts as 'maximum demand' in a group depends on the configuration of a network. Under particular conditions, the demand that can be met can be maximised by switching some demand to a neighbouring group that has some network capacity headroom. According to advice received by the author, such demand transfer is not considered when calculating load indices[9]. Moreover, as also discussed above, there are different ways of defining circuit capacity.

4.4 Generation connections

ER P2/6 and this note are concerned with connections of and reliability of supply to demand. Distributed generation, i.e. generation connected within a distribution network, is considered here only insofar as ER P2/6 recognises the contribution of DG to meeting demand. However, connection of and reliability of supply to demand and the different measures that a DNO might take towards

[9] The author was unable to find published, final definitions of the terms used in calculation of load indices.

that end are not the only drivers for investment or adoption of 'flexible' network interventions. Another driver is the facilitation of connection and operation of generation.

It will not be addressed in any depth here but it may be noted in passing that there is no equivalent to ER P2/6 for the connection of generation. In particular, there is no standard guidance to direct DNOs in how to balance facilitation of access, choices between firm and non-firm access, the occasional, temporary curtailment of generation output and the use of different network measures – reinforcement, active network management, reconfiguration, real-time ratings, voltage regulation, etc. – to meet the distribution licence conditions of:

> "(a) permit the development, maintenance, and operation of an efficient, co-ordinated, and economical system for the distribution of electricity; and
>
> "(b) facilitate competition in the generation and supply of electricity."

and

> "accept into the licensee's Distribution System, at any Entry Point and in any quantity that was specified by the requester in the request, electricity that is provided by or on behalf of the requester."

In an open letter on ER P2/6 in December 2007, Ofgem expressed the view that design of generation connections within a distribution network should be left to bilateral arrangements between DNOs and generators or between DNOs and National Grid Electricity Transmission (NGET) where there is a transmission impact. However, from various discussions with DNOs, not least at Low Carbon Network innovation events, it has become clear to the writer of the current note that there are inconsistencies in the development of such arrangements, that the most economic and efficient actions are not always being taken and that DG that might otherwise contribute to competition in the generation of electricity or to reduction of carbon emissions might, on occasions, be unnecessarily disincentivised from connecting. It is therefore strongly recommended that work is undertaken to address the connection and operation of DG, starting from guidance on network operation that allows a network operator to make decisions in real-time and in operational planning that allow an adequate coordination of different generators' outputs within a framework that reveals costs and benefits of different actions and gives an appropriate sharing of risk and reward between generators, consumers and network operators[10]. Given that a network development planner's job is to facilitate future system operation, such a framework for network operation would, alongside network charging rules (possibly reformed rules that better balance risks between different parties) also provide a stronger platform than existing guides for treatment of generation connections and decisions on where reinforcements or other interventions are necessary.

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[10] It may be argued that the licence conditions of "permit the development, maintenance, and operation of an efficient, co-ordinated, and economical system for the distribution of electricity" and "accept into the licensee's Distribution System, at any Entry Point and in any quantity that was specified by the requester in the request, electricity that is provided by or on behalf of the requester" are in contradiction of each other especially if the latter is interpreted as meaning that firm physical access must always be provided to DG, i.e. such network capacity is provided as to never require the curtailment of DG output. The contradiction is because entirely constraint-free operation of generation is not always the most economic and efficient approach for the electricity system as a whole.

5 Recommendations for a successor to ER P2/6

5.1 Risk and cost-benefit as the basis for a design standard

It is the author's understanding that the review of ER P2/6 initiated by the DCRP will look fundamentally at risk to supply, in particular the probability of different levels of power being interrupted and of different amounts of energy not being supplied. This, in the author's view, is very welcome and represents, in particular, an opportunity to reflect on the value placed on continuity of supply and restoration times for demand groups of different sizes and, as a consequence, the apparent need for reinforcements at 33kV or 11kV relative to the present day costs of different interventions. (One opinion expressed by at least one DNO design engineer is that ER P2/6 over-emphasises investment at 33kV and under-emphasises it at 11kV).

A key part of the review will be the consideration of the contribution that different means of meeting demand might make. This includes DG, flexible demand and storage but also the sorts of interventions addressed by the "Flexible Networks" project, e.g. dynamic network reconfiguration, real time thermal ratings and improved voltage management. Any new standard should make clear that these are all viable options the adoption of which should depend on their cost relative to other options and their feasibility throughout a 'typical' year of operation. That is, the ability of 'smarter' network interventions to contribute to meeting demand (or, for that matter, facilitating generation) depends on prevailing conditions and, in the case of network configuration, the coincidence of particular conditions in neighbouring groups. Any risks associated with such interventions should also be part of an option evaluation and should include a realistic assessment of both the probability and the consequences of, for example, real-time continuous ratings being exceeded. In the latter case, as was discussed above, exceedance of a continuous rating does not necessarily that an asset's critical temperature would be reached or a circuit would be switched out. Moreover, the extent of exceedance, its duration and the probability of occurrence may be such that any acceleration of ageing of the affected asset is insignificant.

5.2 The presentation of a standard

One possible outcome of the ER P2/6 review is that some new characterisations or analysis methods are developed that can guide planners in identifying the need for investment and which investments would be appropriate. However, it is also important to consider how new characterisations or methods will be used. That depends, to a very large extent, on the wording of a standard and any accompanying guidance. In this respect, a lead can be taken from the National Electricity Transmission Systems Security and Quality of Supply Standard (NETS SQSS) and work led by the European Network of Transmission System Operators for Electricity (ENTSO-E) towards the harmonisation of standards across Europe and the development of new standards.

The NETS SQSS has emerged from a number of reviews post industry liberalisation, the first and most fundamental of which took place in the 1990s and resulted in the drawing together of a number of guidance documents covering different aspects of system planning and operation into one document covering both planning and operation. A major feature was the adoption of a harmonised set of terms and a significantly changed expression of security centred on clear and consistent definitions of 'secured events' and the possible impacts of events that action should be taken to avoid. For example, although the criteria for the design of connections of demand were based on those in ER P2/5 (the forerunner to P2/6), it was made clear that, in meeting demand, not only should there not be 'unacceptable overloading' (defined in such a way as to permit the use of short-term and real-time ratings), but voltages should be within acceptable limits. Clarity was also offered in respect of the demand to be met under conditions when planned outages would normally be taken. Draft accompanying guidance, developed in 2005 but not published, also sought to provide clarity on how consequences of events should be assessed, e.g. that both automatic and manual control responses should be modelled.

5.3 Advice on background conditions

The role of a system development planner is to ensure that sufficient facilities are available to the system operator to enable the system to be operated in accordance with operating standards in an economic and efficient manner taking into account both costs of system operation (including costs of losses) and capital, operation and maintenance costs of assets. The planner should therefore, in some way, anticipate or predict the conditions that might be faced by the operator. The main difference between planning and operation of a power system is that the exogenous factors affecting system operation are known with much less certainty the further ahead of real time an assessment is being conducted. As a consequence, the main (but, in the case of the SQSS not the only) difference between the planning or design criteria and the criteria for system operation are that the former defines not only secured events and the consequences of those events that should be avoided but also, at least to some extent, the range of system conditions that should be assessed in respect of future operation.

As has been discussed above, there is significant variation between DNOs in respect of the way in which they derive the background conditions against which compliance with ER P2/6 should be assessed, not least the demand to be met. While it might be argued that some flexibility is a good thing and permits some recognition of the differences between distribution networks in different areas and the customers they serve, it opens up the possibility that some practices lead to the risk of over-investment in network assets relative to actual need (and, hence, to higher costs to consumers) while others lead to risk of under-investment (with higher risks to supply of power)[11]. Without being overly prescriptive (the opportunity should still be left open for adoption of best practice as that practice evolves), a new distribution network design standard or accompanying guidance should give clearer direction than ER P2/6 on the background conditions and exogenous factors to be considered and how to consider them.

5.4 The need for simplicity

A new distribution network design standard and any accompanying guidance should be written having due regard to the nature of a distribution network operator's business. In particular, in comparison with a transmission licensee, its individual assets are much more numerous and have both lower cost and, in terms of the size of demand or number of customers connected, lower value. In addition, historically and in general terms (the exceptional contributions of individuals should not be overlooked), the level of power system analysis expertise found within DNOs has tended to be lower than in transmission licensees. However, critically, the volume of new connections faced by DNOs, whether those connections require DNO approval or not, is much higher than that faced by

[11] Indeed, uncertainty regarding future demand and its growth are one of the motivations for exploration of the interventions addressed in the Flexible Networks project – while investment in conventional network capacity might not be avoided completely, it might be deferred until such time as there is greater certainty of need.

the transmission licensees and is likely to grow massively as low carbon technologies reach higher penetrations. Thus, there is likely to be a strong case for a new distribution network design standard to be formulated in such a way as to be easy to interpret and apply even if that means that the outcome of application cannot be guaranteed to always be completely optimal. Moreover, another benefit of relative simplicity lies in the ease with compliance can be tested and correct application verified.

5.5 The need for consistency across the regulatory environment

A final, strong recommendation is for consistency among standards, conventions and incentives such that DNO behaviours are driven unambiguously towards their customers' best interests *and* DNOs can be confident of recovering their reasonably incurred costs.

There are currently a number of regulations or regulatory initiatives that influence DNO network planning and development. The main ones are:

1. The Distribution Code, in particular the requirement to comply with ER P2/6;
2. the Interruption Incentive Scheme (IIS); and
3. the RIIO-ED1 price control framework, in particular the link to load indices.

Given the licence obligation to comply with ER P2/6, P2/6 might be regarded as defining the minimum network capacity that should be provided in respect of meeting demand. The IIS might then be regarded as providing a basis for assessment of possible investment in *additional* network capacity or network control facilities to improve reliability of supply. These two provisions might ordinarily be expected to provide sufficient motivation for distribution network development for the meeting of demand. In practice, given the definitions of demand groups, ER P2/6 is significant in driving reinforcements only at the primary substation level (where 33 to 11kV transformers are located) and above. Action to date motivated by the IIS and CMLs and CIs has tended to be driven by the impacts of fault events at the 11kV level. However, Ofgem has felt the need to define a further measure: that of 'load indices' as part of the RIIO-ED1 settlement.

In its decision on load indices, Ofgem claimed that the IIS represents a "lagging indicator". This might be assumed to mean that investments driven by IIS are undertaken only after reliability has already been observed to be below the IIS target. This may or may not be true in respect of past DNO behaviour, but it need not be and, even then, perhaps should not be. This is because:

1. The events that affect CML and CI are stochastic and show significant natural variation; even for the same network capacity and configuration and the same demand, CML and CI may be expected to vary from one year to the next. In other words, high CML or CI values in one particular year are not necessarily indicative of a need for investment and low values in a year are not absolute indicators of sufficiency of investment.
2. It is possible to make a reasonable estimate of the expected future value of CML and CI and to identify appropriate network interventions accordingly.

In respect of the latter observation, knowledge of a network's structure, capacity and the number of customers at each location along with suitable average fault rates for different classes of equipment and switching times can, given suitable software, allow useful analysis and comparison of different network configuration and development options.

Another issue with load indices is the apparent inconsistency with ER P2/6 in respect of definition of demand and network capacity. Although the author of this note has not been able to find out exactly how Ofgem's Reliability and Safety Working Group has defined 'maximum demand', circuit capacity, 'duration factors' and the contributions of generation, it is the author's understanding that they are not consistent many planners' interpretation of similar terms in ER P2/6 or what the author has argued above are appropriate in terms of economic and efficient network development. In particular, it seems that load transfer is not taken into account in calculation of load indices whereas ER P2/6 does permit load transfer, in particular under planned outage conditions or as a means of restoring demand. That is, the definitions relevant to load indices seemingly take no account of headroom represented by moving demand at critical times to exploit headroom available elsewhere within the network at those times (and, potentially, moving it back at other times). Given the apparent use of load indices (difficult to ascertain given the paucity of easily accessible published information), shifting demand around potentially means a decrease in the load index for one group but might entail an increase for another one with no net benefit.

Given that ER P2/6 is a licence condition for DNOs, it is clearly anomalous that some different conventions – load indices – are in place that may drive different investments from those indicated by ER P2/6. It is therefore recommended that the interactions between ER P2/6, the IIS and 'load indices' are reviewed. In addition, it is recommended that work is undertaken to develop standards that drive both DNOs and generators towards economic and efficient accommodation of generation on distribution networks.