SCOTTISHPOWER

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14 March 2012

Dear Ian,

TRANSMISSION CONSTRAINT LICENCE CONDITION

Thank you for the opportunity to provide views on behalf of ScottishPower on Ofgem's intended approach to interpreting and enforcing the Transmission Constraint Licence Condition (TCLC) as proposed by DECC.

Our responses to the questions posed in the consultation document are set out in the attached annex. We have also commissioned an independent report from Oxera[1] to provide additional detail on the points raised in this response. We have early results from this work and will provide a copy of the report when finalised.

We have three main comments on Ofgem's proposed guidance document:

a) we would encourage Ofgem to consider introducing a 'safe haven' principle in its enforcement guidelines to minimise the compliance burden for generators;

b) we believe Ofgem should align its tests for excessive pricing more closely to established competition law principles; and

c) we believe prices for inter-trip arming should be benchmarked against the wider market for substitutable balancing services of which inter-trip forms a part.

'Safe haven'

Ofgem's proposed approach to enforcement is to screen all dispatch decisions against its internal model of generation plant economics, taking into account spot fuel and carbon prices, intraday electricity prices, warm up/ramp up costs and 'any other technology/plant specific costs'. If Ofgem suspects, on the basis of its model, that a generator has manipulated its output, the generator would be required to provide clear evidence to demonstrate that their actions can be objectively justified.[2]

As explained in our response to Questions 3 and 4, we believe Ofgem has significantly under-estimated the complexity of economic dispatch decisions and the range of

[1] 'Assessment of the Transmission Constraint Licence Condition, Report for prepared for ScottishPower', Oxera, March 2012
[2] Condoc paras 2.16 and 2.17

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factors that would need to be considered. By way of illustration, the draft analysis by Oxera shows that, averaged across GB, around a third of the time that thermal plants are dispatched, spreads are negative, and around half the time that plants are not dispatched, spreads are positive. A similar pattern is observed in both England and Scotland. Even when Ofgem has adjusted for warm up/ramp up costs and other technology/plant specific factors, we are concerned that there will be a very high 'false positive' rate.

One of the main compliance costs for generators will be the cost of creating and retaining appropriate documentary evidence of all the relevant factors that may have influenced a dispatch decision, should Ofgem subsequently query it. This will be significantly more onerous than the documentation required for normal business governance, and will require new processes and procedures to be developed.

The principle behind our 'safe haven' proposal is that Ofgem should make provisions in its guidance that dispatch decisions or bid prices will not be queried if they satisfy predefined criteria. Generators could then identify in advance that dispatch decisions or bid prices satisfying these criteria are safe from challenge, and lighten their compliance burden accordingly.

We would therefore propose that:

a) a decision to dispatch a generator located behind a constraint would not be challenged if any comparable generator beyond the constraint (and owned by a different company) has also been dispatched at the same time (and similarly for non-dispatch decisions of available plant);

b) the bid price for a generator located behind a constraint would not be challenged if it is not more than say 5-10%[3] below the bid price of a comparable generator beyond the constraint (and owned by a different company).

We would be pleased to work with Ofgem and other stakeholders to refine this proposal further.

Tests for excessive pricing should be aligned more closely to competition law principles

DECC's consultation and impact assessment explains that the rationale for introducing a licence condition rather than relying on competition law relates to specific difficulties in applying competition law, notably difficulties in market definition, and in demonstrating individual or collective dominance.[4]

However, no case is made in DECC's consultation for departing from other established principles of European competition law, notably the extensive case law on the test for 'excessive pricing'. As explained in the draft Oxera report, these tests have been carefully crafted to strike an appropriate balance between the costs and distortions of excessive intervention, and the benefits to market development, and ultimately consumers of deterring abuse. We cannot think of any reason why the same principles should not apply to the electricity generation market.

We are therefore concerned that Ofgem's draft guidance implies that Ofgem does not intend to be guided by these principles:

[3] 'Price increases of around 5-10% are typically used by competition authorities as a benchmark of a small but significant price rise as part of their assessment of the relevant market. However, more work needs to be done to refine this threshold.

[4] DECC Impact Assessment para 29.

> "Equally, the assessment of any potential infringement of this licence condition will be distinct from any assessment of potential competition law infringements and the indicators of potential breach discussed in this guidance are not intended to replicate or correspond to those commonly applied in competition law cases."[5]

We urge Ofgem to reconsider this position, and confirm in its guidance that its approach to assessing excessive pricing will be consistent with competition law principles.

If inter-trip is regulated by the TCLC, arming prices should be benchmarked against the wider set of balancing services

Inter-trip is part of a suite of substitutable services including the Balancing Mechanism, capped out contracts and bilateral trades which collectively are available to National Grid for managing constraints. Oxera's draft report discusses how this market has developed under the influence of growing competition. Average inter-trip arming fees have reduced very significantly over the last 3 years and there are clear indications of a dynamic and strong market having developed for the various advanced balancing services, including inter-trip

Given this strong and growing market, a key indicator in assessing the level of inter-trip arming fees is how these fees compare to these other constraint management services options open to National Grid. This indicator has not been included in Ofgem's non-exhaustive list. Inter-trip is one of the most cost-effective options available to National Grid and it is therefore vital that companies are incentivised to offer it to the maximum extent, even if their plants were not designed to be operated in this way.

If Ofgem's approach to benchmarking, looks solely at the costs of inter-trip arming, rather than the suite of substitutable services, there are two material risks:

- generators may be more cautious in offering inter-trip services;
- the incentive to develop new innovative services will be reduced, if generators expect that such new services may also be subject to price control in future.

Constraints can only be managed effectively if National Grid continues to have access to the full range of options and as many participants as possible are incentivised to compete and innovate in providing these services.

I hope you find these comments useful. Should you wish to discuss any of these points further then please do not hesitate to contact me.

Yours sincerely,

Rupert Steele

Rupert Steele
Director of Regulation

[5] Ofgem condoc para 1.8

ANNEX

SCOTTISHPOWER RESPONSE TO DETAILED OFGEM QUESTIONS

Question 1: Do you agree with our interpretation of uneconomic dispatch?

We agree with the aim of ensuring that generators do not try to manipulate constraints but in our view the examples chosen do not recognise the structure of the competitive GB electricity market nor do they recognise the full range of factors that a prudent operator needs to take into account when deciding the most economic option for its generation plant.

The consultation paper cites as its prime example of uneconomic dispatch the situation where a generator dispatches a coal fired plant in a certain location when it would have been more economic to dispatch a gas fired plant in a different location. This, however, does not recognise the central role the GB wholesale market plays in a generator's decision as to whether dispatch is economic or uneconomic. A portfolio generator's operational trading strategy will be designed to ensure that each of its plants only operates when it makes a positive contribution. For each station it will seek to maximise generation when contribution is positive (selling any surplus against its contract position into the wholesale market) and minimise generation when contribution is negative (purchasing any shortfall against its contract position from the wholesale market).

The existence of a competitive GB wholesale market with a transparent half-hourly market price means this is the price against which a generator will judge whether dispatch is economic or not and thus a generator only owning a single plant is in the same position as a portfolio generator when deciding the economics of dispatch. There is no "lump of electricity" which a generator needs to share out among its plants.

Ofgem sets out in its guidance a non-exhaustive list of the factors it will take into account when deciding whether dispatch is economic or not. We are concerned that this does not recognise some very important factors affecting a generator's decision and we set out these concerns below. We are also concerned that Ofgem's approach would appear to be to assess the economics of dispatch against spot market spark and dark spark spreads and then seek information from any generator behind a constraint whose generation pattern is not justified by these spreads.

As explained in our covering letter, we are concerned that this could lead to a significant proportion of generation being queried. This would in turn place a significant administrative burden on generators and we urge Ofgem to consider including within its guidance a 'safe haven' approach whereby dispatch decisions and bid prices which satisfied pre-defined criteria would be safe from challenge.

Question 2: Is the use of 'within-day' fuel and electricity prices to calculate generation profitability the most realistic approach?

Within-day fuel and electricity prices are suitable as a starting basis for determining generation profitability but there are many factors including those set out below which need to be taken into account to determine the actual costs facing a generator.

Question 3: What other costs, if any, should be included in our initial analysis of dispatch decisions?

Coal prices

Ofgem states that it will use spot coal prices to calculate dark spreads, presumably based on the industry standard coal specification. Coal station operators are however unlikely to use this simple fuel statistic when deciding the economics of dispatch. A prudent operator will obtain coal from a diverse range of sources in order to comply with plant emissions limits, maximise value and reduce exposure to risks arising from a single point of failure in the delivery logistics chain. Each coal has specific physical properties, and is priced accordingly, expressed in terms of a price differential to the industry standard coal specification. For example Russian coals tend to have a lower sulphur content than standard and thus command a premium whereas Scottish coals tend to have a higher sulphur content and thus sell at a discount. An operator is likely to value coal on a replacement cargo basis, assuming spot cargos for delivery in the quarter ahead. The basis of this value will be dependent on the constraints facing the operator and on its physical coal storage and logistics chain.

Supply chain logistics have been recognised in the guidance as issues which could impact the economics of dispatch but Ofgem state that generators would be required to produce convincing evidence that their dispatching was impeded because of logistical issues before Ofgem would accept this as objective justification. However, in the case of coal, transportation costs, port handling charges and storage costs are so significant that these issues are fundamental to the economic dispatch decision rather than factors which only need to be considered on special occasions.

Large coal generation plant is likely to use a blend of imported coals and domestic coals. Some ports can handle large cape sized vessels while others can only handle smaller panamax and handy-sized vessels. Port charges are incurred for unloading and also storing coal and further costs are incurred for transporting coal to the power station by rail or road. Port handling and freight contracts are likely to have take-or-pay obligations meaning that if insufficient volumes are delivered under the contract, the generator can face significant financial penalties. These factors can significantly impact the economic dispatch decision.

A large coal generator should have storage capacity at its power stations and the ports it contracts with which would be sufficient to cope with short term changes in generation volumes relative to that forecast. However, in the event of significant and long-lasting changes, there may be a requirement to take actions to manage coal stocks. These actions may include:

- selling cargos, sometimes at distressed prices;
- selling coal stocks at ports to third parties;
- reducing domestic coal volume deliveries;
- transporting coal to third party premises for storage and subsequent re-transportation back to the plant at a later date;
- introducing a negative coal stocking risk premium to increase generation volumes.

Coal generators have been required to consider such options in the recent past when evaluating the economics of dispatch options.

Power prices

The guidelines state that Ofgem will use within day electricity prices as the basis of its assessment of the economics of plant dispatch. It is also necessary to recognise that generators may choose to sell output into the forward market subject to a hedging process. Generation output is then continuously re-optimised, in the light of changing plant capabilities and forward market prices, with the aim of maximising value from market volatility. This process of re-optimisation and trading allows generation plant to respond to forward market pricing signals from a point some years ahead of delivery to gate closure. There is sufficient liquidity in the market to enable generators to operate such a strategy, particularly on a forward basis and also at the day-ahead stage where volumes can be finally optimised through the over-the-counter market or through exchanges.

A consequence of these more sophisticated strategies is that there will be occasions where the volume in the spot power exchange market is not sufficient for a large generator to re-optimise its whole plant immediately before gate closure. There may therefore be half hours in which the dispatch decision appears uneconomic, but is nevertheless based on a rational trading strategy.

Start-up costs

The guidelines state that Ofgem intends to adjust profitability calculations to take account of any warm up/ramp up costs for generation units. This will show that start up costs at coal plants are much greater than at modern CCGT plants with coal plants requiring longer hot and cold start processes resulting in more fuel being consumed to start the energy–hungry heavy fans and pumps central to coal-fired plant operations. A typical hot start at a CCGT could be 90 minutes whereas a cold start at a large coal unit could extend to over 8 hours.

These are the direct costs associated with a start up but there are also indirect costs which can be significant which also require to be taken into account.

There is a risk of reduced availability arising from flexible operation of power plant and this can be particularly significant for older coal plant. Shut downs and start ups are more stressful on plant than continuous operation and can accelerate maintenance requirements or directly result in plant failure. Older coal plant originally designed for base load operation is particularly susceptible to boiler tube leaks caused by changing temperatures and pressures which can result in a plant outage of several days to enable a repair to be completed. While the direct cost of a repair can be significant, the main costs are the opportunity costs from not being able to generate as planned in the competitive power market, not being able to participate in the balancing market and not being able to provide ancillary services. For a 600MW unit these opportunity costs can be over £100,000 per day and thus the risk of incurring these costs must be taken into account when scheduling plant.

There is also a risk, particularly for older coal plant, that during the start-up process the ramping rate is not as fast as expected and synchronisation is delayed. In such a situation output over the start-up period will deviate from forecast and thus imbalance costs will be incurred to cover the difference between actual and expected. This risk needs to be assessed and incorporated into the forecast start-up cost when scheduling plant.

Physical plant constraints

The guidelines also state that Ofgem intends to adjust profitability calculations to take account of any technology/plant specific costs for generation units.

Each generating unit will have its own peculiar physical plant constraints which will vary with age, condition and degree of automation. All equipment has a finite life, generally determined by operational hours, process conditions and number of start/stop operations. Plant condition changes over its operational life and this needs to be taken into account when scheduling. Modern CCGT plant is fully automated to meet the manufacturer's imposed limits and thus during ramping down and ramping up the operator is only required to assume an overview role ensuring the plant automatic systems enact their functions correctly. Older coal plant was not built with full automation and while automation may have been introduced with plant upgrades, coal plant automation capability cannot meet the capability of CCGT plant systems since the fuel product is significantly more variable and difficult to process. Thus coal plant performance is most likely to be significantly more variable than CCGT plant performance.

The configuration of generating units within a station can also give rise to further physical plant constraints. Resource limits affecting the overall station, such as manpower and water, can place limits on the number of units that can be simultaneously ramped up. There could thus be a significant delay required between synchronising individual units at a multi-unit station and this needs to be taken into account when assessing the cost of turning down and ramping up generation.

Question 4: Are there any further important arguments that provide objective justification for uneconomic dispatch?

Large Combustion Plant Directive – opted out plant

Ofgem has recognised in the guidelines that there are European and UK policies that affect the profit optimising strategy of generators and thus dispatch decisions and has specifically identified the Large Combustion Plant Directive (LCPD) as one such regulation. However the consultation cites the example of a generator with a coal plant opted out of the LCPD deciding to run the remaining hours of the unit despite having more profitable options available. The dispatch decision of an opted out generator will however be based on ensuring that the greatest financial benefit is secured from the finite remaining available operating hours for that plant under the terms of the LCPD rather than on the availability of other options. Thus a generator only owning a single opted out plant is in the same position as a portfolio generator owning such plant when deciding the economics of dispatch.

A further complication can arise as a result of LCPD hours being limited at a stack level rather than an individual unit level. For a station where more than one unit is connected to a stack then the dispatch decision cannot be taken purely on a single unit basis. If only one of the units connected to the stack is available to run then the dispatch decision requires to compare the benefit secured from running the single unit at that time compared to running one or more of the units connected to the stack at a later date. This comparison will be a function of both the anticipated closure date and the anticipated output schedule in the intervening period based on a number of variables including plant availability and forward market prices. The closure date itself will be subject to an economic analysis of fixed and variable costs and revenues, and subject to future re-development options of the site.

Thus for plant opted out of the LCPD the economic dispatch decision is particularly complex and as a result any assessment of the economics of dispatch for such plant based purely on spot market spreads would not be sufficiently accurate to use even on a preliminary basis.

Large Combustion Plant Directive – opted in plant

The economic dispatch decision can also be complex for plant opted in to the LCPD, particularly plant opted in under the National Emissions Reduction Plan (NERP), which will be subject to annual emissions limits, as opposed to plant opted in under Emissions Limit Values (ELV) which will be subject to instantaneous limits being observed. While this will also affect gas plant the major impact will be on coal plant subject to annual SO2, NOx and dust emissions limits.

In order to stay within an annual SO2 limit the options open to a plant would include the use of Flue Gas De-sulphurisation equipment, purchasing SO2 permits from other NERP market participants, purchasing lower sulphur coal at a premium and reducing plant output during periods of least value.

In order to stay within an annual NOx limit the options open to a plant would include the use of NOx reduction equipment, purchasing NOx permits from other NERP market participants, purchasing coal of a type likely to emit reduced NO_X volumes at a premium, and reducing plant output during periods of least value.

The economic dispatch decision for such plant requires to take the options above into account and thus the correctness of dispatch decisions cannot be assessed on the basis of spot market spreads alone.

Industrial Emissions Directive – opted out plant

The Industrial Emissions Directive (IED) recasts the LCPD emission limits for SO2, NOx and dust from the start of 2016. The IED includes a derogation allowing generation plant an exemption from the new emission limits provided the plant does not operate for more than 17,500 hours from 2016 to 2023. Plant opted out of the IED will thus face similar complexities in its economic dispatch decision as plant currently opted out of the LCPD and thus for such plant the correctness of dispatch decisions will not be able to be assessed on the basis of spot market spreads alone.

Agreements with National Grid

Generators can enter into bi-lateral contracts with National Grid which require them to schedule plant compliant with contractual obligations rather than on the basis of economic dispatch.

Generators can compete in competitive tenders operated by National Grid for firm frequency response contracts under which the successful generator is required to operate units during agreed windows at pre-agreed output levels regardless of market prices. This may result in either tranches of in-merit output being withheld or operating when out-of merit, when judged against economic dispatch criteria. Once a generator has contracted for such a service it would be a breach of contract to operate subject to a different schedule which took account solely of economic dispatch criteria.

Certain generators can also compete to provide non-tendered fast reserve to National Grid whereby units are instructed by National Grid to synchronise to the system in

order to provide very quick response if required to meet demand pickups, plant trips and unexpected demand changes. These services are competitively contested by generators able to provide the service. Such generators would not schedule their plant to run when in their assessment the reward from providing this service to National Grid would be greater than the award available from forward or spot peak/off-peak power spreads while also taking account of the other factors impacting economic dispatch.

Some generators can also compete in competitive tenders operated by National Grid to provide fast reserve services which would result in contracted units not being scheduled by the generator to run during agreed windows regardless of the peak/off-peak power spreads. In return for availability, nomination and utilisation fees under the terms of such a contract National Grid would be able to instruct volumes via the balancing mechanism at very short notice. Once a generator has contracted for such a service it would be a breach of contract to operate subject to a different schedule which took account solely of economic dispatch criteria.

Question 5: Are there any objective justifications cited above which should not be considered in our assessment?

The guidelines state that Ofgem will consider any evidence presented by the licensee alleging an objective justification related to mechanical or technological failure of plant that leaves it inoperable and means that the generator has had to dispatch alternative plants. As in other parts of the document this fails to recognise that the economic dispatch decision is taken on a separate plant by plant basis. If these alternative plants had been economic then they would already have been dispatched. A portfolio generator will be faced with the same decision as a generator owning only a single plant when its plant has an unplanned outage. The most economic option in the event of an unplanned outage is likely to be to purchase any shortfall against contract position from the wholesale market.

Question 6: Do you agree that the indicators outlined above are useful for Ofgem to consider when determining whether the bids are excessive or not?

The most important indicator in the competitive balancing services market is comparable generator benchmarks and this has been included in Ofgem's list. We agree that in such a comparison submitted bids should be included as well as accepted bids and that bids should be compared for all equivalent plant in the GB market irrespective of whether they are behind the constraint or not. When comparing bids it is essential to separate out bids for incremental reduction in output from bids requiring the unit to close down. Bids requiring the unit to de-synchronise will be significantly lower since the cost of starting up the unit will require to be incorporated into the bid price.

When comparing bids from coal plant it is also necessary to identify whether the plant is opted in or opted out of the LCPD as this can significantly impact bid economics. For LCPD opted out plant bid economics are complicated by the need to recognise that the unit has finite remaining operating hours and also how this limit applies to individual units or groups of units. Bid economics can also be complex for plant opted in to the LCPD, particularly plant opted in under the NERP, which will be subject to annual emissions limits.

We also agree that historical bids during non-constrained periods should be considered when assessing the level of bid for a plant during a constrained period. It is unlikely that the existence of a constraint would change the dispatch or bid economics for a

plant behind the constraint and thus if a plant is seen to change its dispatch decisions or bid level when constraints are in place then the operator should be required to justify its actions.

We expect that the importance of these factors when comparing bids will be explained further in the Oxera report, when available.

Question 7: Are there other factors or indicators that Ofgem should consider in interpreting this circumstance?

While Ofgem has identified the main factors and indicators requiring to be considered in assessing bids we believe the complexity of doing so has not been fully recognised. This is particularly true under the category of avoidable costs where the range of factors set out in the answers to the questions above as needing to be addressed in relation to the economics of dispatch are also relevant when considering bid economics. Fuel prices, power prices, start-up costs, physical plant constraints, relevant European and UK policies and agreements with National Grid all need to be taken into consideration when setting bid levels.

The guidance does not recognise the particular uncertainty facing wind generators who are required to forecast wind speeds in order to estimate the revenue they will be foregoing if their bid is accepted.

Question 8: Are there any further important arguments that provide objective justification for seemingly high bids?

When assessing bid levels from plant behind a constraint it is important to recognise that this is only one of the options open to National Grid for managing constraints and that utilising the Balancing Mechanism in this way is towards the more expensive range of available tools, principally because of the corresponding usually expensive offers accepted on the other side of the constraint. Plant can provide a range of other constraint management services to National Grid including capped output contracts, bilateral trades, floored bid prices, commercial inter-trip and unlimited inter-trip arming contracts. These options which are competitively tendered for are likely to be significantly cheaper for National Grid since they involve payment on only one side of the constraint. When assessing the service provided by a particular plant to National Grid for managing constraints it is necessary to consider the full range of services offered by that plant and not to concentrate solely on the bid level.

Question 9: Are there any objective justifications cited above which should not be considered in our assessment?

We agree that contractual obligations could be an objective justification for lower bid prices such as generators having arrangements with suppliers to maximise renewable generation. If, however, such arrangements are resulting in significantly higher constraint management costs than justifiable, generators and suppliers should be incentivised to enter into different arrangements which would be less detrimental to the market as a whole.

Question 10: Do you agree with our definition of arming fees, and that this is the relevant price to capture under this circumstance?

The arming fee is the major cost incurred by National Grid when entering into bilateral contracts with generators for commercial inter-trip services and as such is the most important price to consider when assessing inter-trip costs. It is however necessary to recognise that while it is open to National Grid to negotiate arming fees charged on a half-hourly basis for the period of arming it is also open to them to negotiate fixed fees for extended periods of unlimited arming and this may be the most economic option for National Grid for an extended period of arming.

Question 11: Do you agree that the indicators outlined above are useful for Ofgem to consider when determining whether inter-trip arming fees are excessive or not?

A key indicator in assessing the level of inter-trip arming fees is how these fees compare to the other constraint management services options open to National Grid. This indicator has not been included in Ofgem's non-exhaustive list with proposed benchmarking being restricted to inter-trip arming fees charged by comparable generators. Inter-trip is part of a suite of substitutable services including the Balancing Mechanism, capped out contracts and bilateral trades which collectively are available to National Grid for managing constraints.

In assessing prices charged for inter-trip arming, it may also be necessary to take into account the potential costs of a trip, if those costs cannot be fully recovered through the tripping fee.

Tripping fees are generally set at a level broadly commensurate with the day to day costs that may arise from the operation of a trip including the lost output in the time until the unit is re-synchronised, the need to trade out the position during that period and the need to perform standard processes before the re-start. Tripping fees set at this level may be substantially below the risk-weighted cost of major damage from an inter-trip event at a station.

The triggering of an inter-trip is a stressful event for a power station, both in terms of the electrical consequences of suddenly disconnecting the unit from the load, and in terms of safely dissipating the very substantial heat and mechanical energy that no longer has an outlet. We have previously approached National Grid to discuss setting tripping fees at a level to compensate for the risk of a major failure caused by the trip but they have not been willing to agree to this. In these circumstances, station operators would either have to incorporate these costs into the arming fee, or withdraw from the inter-trip market.

We agree that historical inter-trip arming fees are important indicators when assessing the level of current fees. Average arming fees have reduced very significantly over the last 3 years showing evidence of how the competitive constraint management services market has enabled National Grid to effectively use inter-trip to reduce constraint costs.

Question 12: Are there other factors or indicators that Ofgem should consider in interpreting this circumstance?

Commercial inter-trip and unlimited inter-trip arming contracts are bilaterally negotiated contracts which National Grid has been able to use effectively to reduce constraint

costs as will be explained in the Oxera report. If there is a potential for the agreed terms of these contracts to be deemed to be in breach of a licence condition then generators may regard the least risk option as being not to enter into such contracts. The effect of including inter-trip in the TCLC could therefore be to reduce the options for National Grid with a consequent increase in constraint costs.