December 2, 2011

Socrates Mokkas
Ofgem
9 Millbank
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Dear Mr Mokkas,

Electricity Capacity Assessment: Measuring and modelling the risk of supply shortfalls

The Brattle Group and Astrape Consulting are pleased to respond to your consultation on modeling the risk of supply shortfalls.

Our main concern is that the proposed modelling approach does not involve hourly chronological modelling. Based on our experience of carrying out similar exercises in the US, we consider that hourly chronological modelling is essential to achieve a realistic estimate of supply shortfalls. We were also surprised that there was no mention of evaluating the economics of reliability, given that this something discussed in the white paper in relation to setting the parameters for a capacity mechanism.

I also enclose a paper that we have produced relating to the economics of resource adequacy planning which discusses many of the issues raised in the consultation document.

Yours sincerely,

Serena Hesmondhalgh

Serena Hesmondhalgh

Principal

1. Responses to consultation questions

Question 1: *Do you agree that the de-rated capacity margin is a good indicator of future capacity adequacy?*
Yes, we agree this is a reasonable metric. However, the de-rated capacity of intermittent resources is difficult to estimate because of the annual volatility of the contribution of intermittent resources during peak conditions. Some years, the contribution of intermittent resources to reliability may be substantial and other years it may be minimal. See our additional comments regarding a methodology to calculate this value.

Question 2: *Are there any measures of risk other than LOLE and EEU that we should report and what are their comparative advantages*?
As discussed in the attached NRRI Paper[1], we recommend not only calculating physical reliability metrics, such as LOLE and EEU, but also evaluating the economics of reliability. This would also contribute to the requirement to determine the costs of different levels of reliability that is included in the white paper. Additional reserve can have substantial economic impact and provide more value than only avoiding firm load shedding. They also lower the frequency and volatility of scarcity pricing situations, and help avoid the dispatch of expensive resources on either the demand or the generation side. An economic metric provides incremental insight when determining appropriate capacity reserves and evaluating the benefits of various capacity market structures.

Question 3: *Are there any additional key input assumptions that we should consider in the modelling?*
We recommend that the following additional key input assumptions (or approaches to assumptions) should be considered:

- Weather Modelling: The fact that load and available capacity are so dependent on hourly weather means that we suggest modelling multiple weather years in chronological order instead of random stochastic draws of hourly load. The capacity of thermal resources could also be modeled hourly as a function of temperature and hence the combined impact of weather on load shapes and available capacity would be captured. See Question 12 for more details.
- Load Forecast Uncertainty: uncertainty that is based on economic growth should be included as part of the probabilistic analysis and not treated via scenarios.

Question 4: *Do you agree that the use of stochastics (probability distributions) to model short-term variation of key input variables is the best available method? Do you agree with the use of scenarios and stress tests for capturing long term uncertainty in key input variables?*
We agree that the modelling of generator forced outages must use a stochastic process. As far as modelling weather and its impact on load shape, intermittent resources, and thermal resources, we

[1] Carden, Pfeifenberger and Wintermantel, "The Economics of Resource Adequacy Planning: Why Reserve Margins Are Not Just About Keeping the Lights On," National Regulatory Research Institute Report 11-09, April 2011.

consider that a better method would be to simulate a full range of weather years. We accept that such data for *proposed* intermittent resources will not be available but historic wind speed data would be sufficient. See also answers to Questions 5 and 12.

Question 5: *Do you agree with the proposed approach to modelling wind availability?*
We agree that the technical specifications of wind turbines should be used to correlate wind speeds to production. However, constructing wind generation availability distributions to estimate the hourly contribution of wind may not be appropriate. The correlation of wind speed and other weather conditions needs to be taken into account to understand wind's contribution to reliability. This is one of many reasons that reliability modelling should be performed using an hourly chronological model. See Answer to Question 12 for further recommendations regarding weather and wind modelling.

Question 6: *Do you agree with the proposed use of NGET"s existing data and assumptions, regarding, in particular, commissioning and decommissioning dates and embedded generation?*
The TEC register contains data for plants whose construction is yet to be confirmed e.g. those at the scoping, or awaiting consents stage. Similar, the SYS only assumes the retirement of plants with confirmed closure dates. If the analysis is going to look 4 years out (as it is suggested would be required for the capacity mechanism in the white paper), how these assumptions are modified to produce more realistic capacity assumptions could have a significant impact on the outcome. To rely simply on "informed decisions" will lead to a lack of transparency.

Question 7: *Do you believe that Ofgem should require industry stakeholders to submit up-to-date data with regard to commissioning and decommissioning dates and embedded generation? Which industry process will ensure the confidentiality of information provided?*
It will clearly be important to ensure that accurate data on embedded generation is included so, to the extent that NGET will not have these data, they need to be collected in some other way. With regard to commissioning and decommissioning data, we would expect such decisions (particularly with regard to decommissioning) to be reviewed on a regular basis. Hence, any data that are provided for a four year forward looking period are likely to be approximate – it would not be appropriate to force companies to keep to their original commissioning and decommissioning schedules if market circumstances changed. Nonetheless, requiring such information to be provided might provide more accurate analysis that simply relying on NGET data.

Question 8: *What are your views on how best to model LCPD opt-out plants' restricted running regimes?*
LCPD (and, later on IED) opt-out plants will presumably seek to maximize the margins that they can earn during their restricted running regimes. This suggests that some form of electricity market modelling, taking account of forward fuel and carbon prices, should be used to determine their likely profile of operation e.g. does it seem likely to be more profitable to generate in the future rather than now? The fact that they are likely to be operating at low load factors reinforces the need for an hourly chronological approach to ensure that the technical restrictions on their operating regimes are appropriately captured.

Question 9: *Which of the two approaches for modelling electricity interconnection flows will provide the most realistic flows? If you favour the scenario based approach, what are your views on reasonable scenarios to run?*

We favour Option 2, in which the surrounding regions are actually modelled. Interconnection with surrounding countries can have a significant impact on reliability as weather and generator outage diversity can provide substantial benefits. This should be simulated using a transportation model. Also, the price during capacity shortages will have an impact on the economic analysis assessing resource adequacy, and can have an impact on physical reliability if price responsive loads are considered.

Question 10: *Under what conditions would users respond by curtailing their demand and how would you go about modelling this? Is it worth Ofgem requesting data from DNOs on self-interruption and interruptible contracts?*

As smart meters and a smart grid are rolled out, the roll of demand-side response is likely to become increasingly important and so will need to be captured appropriately. In the first instance, discovering how much demand response is currently available seems worthwhile in order to determine whether ignoring it is unlikely to lead to an unacceptable level of inaccuracy in the modelling.

Note that if it is decided that demand response needs to be included in the modelling from the start this reinforces the need for chronological modelling to ensure that appropriate dispatch constraints e.g. call constraints in interruptible contracts, are included

Question 11: *Is historical data of scheduled outages a good indicator of future patterns of scheduled maintenance timings?*

Historical data are sufficient if planning data are not available.

Question 12: *Will treating half-hour periods independently have significant effects on our estimates of the de-rated capacity margin and risk of supply shortfalls and how should the model take into account half-hourly cross-correlations?*

Treating periods independently will have substantial negative impacts on both the accuracy and precision of the results of the model. Resource adequacy assessments must use an hourly chronological model. The following points demonstrate the error in modelling time periods as independent conditions:

1) The frequency and duration of severe weather and, therefore, high load periods cannot be captured if periods are modeled as independent conditions. These high load periods typically persist for a few days and correspond to times when reliability problems may occur.
2) Accurate representation of available dispatchable capacity is difficult.
    a. Using average forced outage rates to come up with a distribution of MW offline is very inaccurate.
    b. The forced outage rate of a system is dependent on recent load conditions. If the past three weeks have had high demands due to severe weather, the equivalent forced outage rate of the system will be higher than if the weather has been more normal.

c. The exhaustion of demand response resources will not be captured if load is not modeled in chronological order as well as energy constraints on hydro and pump storage resources.

3) Reliability is a function of what has happened in previous hours
   a. If one or more large units fail, available capacity that is offline may not be able to start up in time to prevent a reliability problem.
   b. Load forecast errors and wind forecast errors can affect the ability of a system to respond to a disturbance event due to start up times, minimum downtimes, and other unit constraints.

Question 13: *Are there any boundaries other than Cheviot that may significantly affect the risk of supply shortfalls?*

No comment

2. Additional Comments

Robust simulation models take significant time and multiple iterations and need to be used in a variety of environments before becoming mature. Consequently, based on our experience in the development of a reliability model that has been utilized for over 25 years in the U.S., we fear that the task laid out is extremely ambitious given the nine month time frame allotted unless a relatively fully developed model is already available. To the extent that this is not the case, we suggest that OFGEM and NGET look at commercially available models to make sure that significant effort and time is not wasted.

In our reliability analyses, we use a commercially available reliability tool called SERVM which is an hourly chronological model for measuring resource adequacy. Since it is impossible accurately to capture the correlation between load, temperature, wind speed, diversity, and other weather related variables when they are treated independently, SERVM builds full 8760 weather profiles so that each component represents realistic conditions and correlations. Each weather profile represents how the system would look in a future year if it were to experience exactly the same weather conditions as have actually been experienced historically. So the temperatures, wind speeds, and other weather data from a past year are used to construct a load profile, wind production profiles, unit capacity information and other system conditions for a future year. We can build 50 or more unique synthetic weather shapes which are sufficient to guarantee that all possible combinations of all variable components are captured. For each weather year we apply economic load forecast error multipliers (based on uncertainty surrounding economic growth and its impact on future load) with associated probabilities (resulting in 50 weather years x 7 load forecast error multipliers = 350 scenarios with associated probabilities). Each scenario is simulated for 400 iterations for unit outage convergence resulting in 140,000 (250 * 400 iterations) 8760 simulations for each reserve margin level. The unit outage modelling captures the frequency and duration of outages as well as multiple de-rated states for a unit

By running the model in chronological order and using an unlimited number of failure states, we find that cumulative unit outage distributions are much closer to actual data than using a simplistic convolution method or cumulative outage probability tables. Units in the model fail similarly to how they would fail in reality allowing the system to be forced to respond and have the ability to simulate notice of insufficient margin (NISM) situations.

As discussed in the NRRI paper, see attachment, pricing in each region or country is developed based on the marginal resources unless capacity is scarce in which case scarcity pricing is assumed. Since SERVM is a transportation model, the model will economically allow neighbouring markets to share power. Each region's load and generators can be modeled as well as the import capabilities between regions. In this way, it would be possible to model the impact of constraints within the GB market as well as the impact of interconnection to other countries e.g. France, Ireland, Netherlands and so on.

Because our base case model already incorporates 50 weather years, evaluating the capacity credit of a wind resource is fairly simple. We model the hourly wind speeds for a wind resource over 50 years capturing the correlation to load. Then we replace the wind resource's nameplate capacity with a fully dispatchable resource of the same size that has no forced outages and re-run the same simulation. The ratio of the LOLE between the two scenarios provides the capacity credit of the wind resource and its contribution to reliability.

Historical wind data from the past 1-2 years should be adequate for the development of a neural network model to backcast distributions of wind speeds. Based on our experience, using climate models to get long-term historical wind data is a less reliable indicator of wind capacity value than using recent actual wind data to backcast historical data. Since the capacity credit of wind resources is highly sensitive to the weather year selected, we believe it is imperative to develop a significant number of scenarios.

3. About *The Brattle Group* and Astrape Consulting

The Brattle Group provides economic consulting services to the energy industry market participants, system operators, and regulators throughout the world. We advise clients on a range of energy industry matters, including electricity market design, resource adequacy planning, transmission planning and cost recovery, renewables, demand response, and energy market trends. We also provide testimony in regulatory and legal matters. Our clients include electric and gas utilities, public power entities, state and federal agencies, independent system operators and regional transmission organizations (RTOs), independent power producers, demand response providers, and trade associations.

Astrape Consulting provides consulting services to energy industry's electric utilities, regulators, and other market participants. Our core focus is in resource planning and especially resource adequacy for larger systems. We are the exclusive licensor of the Strategic Energy Risk Valuation Model (SERVM) which is used to perform reliability assessments such as but not limited to reserve margin analysis, intermittent resource penetration, and demand response evaluations. Astrape has performed these types of studies for clients across the U.S. SERVM is the only commercially available model that can perform not only traditional LOLE reliability analyses but also simulate the economic impacts of reliability. The model has been used for economic reliability analysis for over 25 years. The model originated within the Southern Company in the mid 1980's and Astrape Consulting became responsible for the on-going upgrades and maintenance in 2005.