

What goes up must come down (unless it is BSUoS)

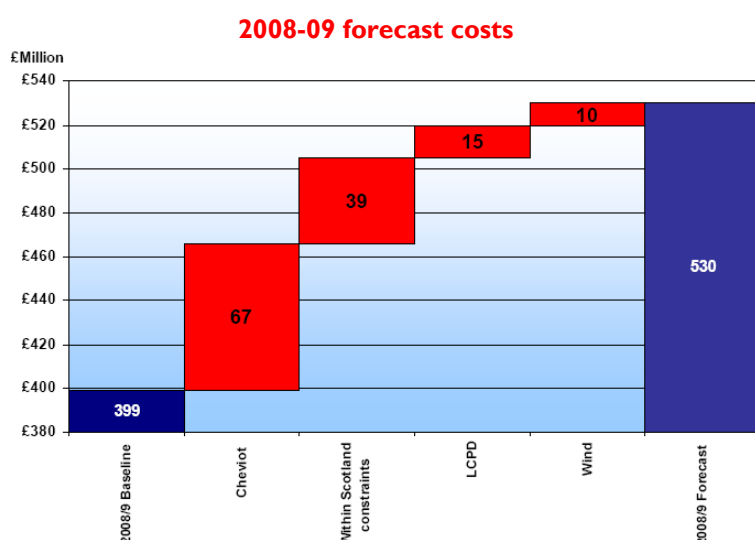
In November (*Energy spectrum 107, p 2*) we considered, and welcomed, Ofgem's decision to trial a new process for developing one year incentive schemes from 1 April 2008 in both electricity and gas for National Grid (NG) in its role as system operator (SO). Under this process NG has since developed and consulted upon its own set of initial proposals (*Energy spectrum 116, p11*), the consultation closing last Friday.

For electricity, which is the focus here, it has developed six alternative schemes offering varying degrees of targeting and risk. Having taken into account the consultation responses, Ofgem will publish final proposals at the end of February. A major theme for the electricity scheme was that central forecasts of costs imply that balancing services use of system (BSUoS) costs are set to rise (again) and that there are also significant uncertainties around these. In this *Energy perspective* we examine the drivers of the cost increases and NG's incentive scheme proposals and reiterate our arguments regarding the need for further, more structural change in addition to the process changes being trialled.

A shorter-term perspective

In November Ofgem held a workshop to consider, as part of its wider review of the functions and role of the SO, the possibility of moving to multi-year incentive arrangements. It quickly decided not to go down this route at least for 2008-09. In a covering letter to NG's initial proposals in December the regulator acknowledged there was little support for it giving priority to this, and it said many of the concerns related to the difficulty of establishing a long-term regime while simultaneously managing other likely changes that will have an impact on SO costs and incentives. (Although it noted that other factors, such as work connected to achieving the 2020 renewables target, the review of transmission access and the cash-out review may require that the longer-term system operator issues are revisited sooner.)

But a further workshop hosted by NG on 10 January also threw into relief the extent of uncertainties surrounding key drivers of balancing costs and their possible effects in the shorter term. For the current year, 2007-08, NG's central forecast for Incentivised Balancing Costs (IBC) has increased to £480mn, against an initial forecast of £440mn. The company attributed this to increased costs of transmission losses, power prices and the net imbalance volume. It now forecasts a loss on this year's incentive scheme of £7mn. And for 2008-09 NG's central cost forecast is £530mn, within a wide range from £471mn to £603mn reflecting the difficulties of forecasting a range of variables and market conditions.



Going forward it has identified three main drivers for cost increases against a baseline cost of £399mn (against a £400mn figure for the current year) (see figure left):

- increasing outages on critical boundary circuits, particularly impacting Cheviot and within Scotland constraints;
- the introduction of the Large Combustion Plant Directive (LCPD); and
- the continuing increase in wind generation.

The first of these reflects a ramp up of Transmission Investment for Renewable Generation (TIRG) works on the Cheviot Boundary and in Scotland during 2008-09, with forecast costs for both exceeding £100mn (an increase of some £40mn year-on-year), reflecting increases in weeks of outage from eight to 30 weeks.

With the LCPD having only come into effect on 1 January, NG has only had a few days' experience under the new regime, which limits opted-out stations to 20,000 hours running between 2008 and 2015, at which point they must close. It considers the effect of the LCPD is a "significant unknown", but that early signs suggest a high proportion of opted-out stations will change behaviour. Taking into account the costs of constraining plant running, its central forecast is £15mn, with a range of between £6mn and £30mn.

The third cost driver is the impact of increased wind generation, which NG expects will impact on reserve levels, the management of frequency, demand forecasting (as generation not metered by NG is seen as demand volatility) and constraints. It forecasts that changes to wind capacity—its best view is this will rise from 2.5GW to 3GW for 2008-09 compared with 2007-08—will increase operation costs by a central forecast of £10mn, £8mn of that due to higher reserve costs. But notably, in a discussion at the workshop on the longer-term costs of increasing wind, NG indicated that additional costs might be as high as £100-£120mn by 2012-13. It also stressed the need to develop mechanisms to resolve the problem in the longer term (such as through passive response mechanisms as discussed in the initial proposals document.)

And NG has also identified an additional source of uncertainty in transmission losses, which have been rising since the introduction of BETTA. It admitted there were problems with accurately modelling losses and has created the forecast for next year by extrapolating historic trends, raising it 10% to 7,445GWh, and has suggested a dead-band on the volume to reflect uncertainty in the forecast.

The bottom line

IBC is the main component of BSUoS, but a number of adjustments have to be made to translate this into an estimate of the full-year BSUoS charge seen by grid users and ultimately customers. Adding to the IBC central estimate of £530mn a Net Imbalance Adjustment of £162mn and SO internal costs of £96mn gives a central forecast for BSUoS for 2008-09 of £788mn, giving a charge of £1.15/MWh (with a range of £729mn (£1.06/MWh) and £861mn (£1.25/MWh).)

This forecast represents a continuation of the recent clearly rising trend and is against a historical perspective where BSUoS was stable from the inception of the current arrangements in 2001-02 through to 2004-05 before leaping over 50% under Betta. Essentially—assuming these or similar figures eventuate—BSUoS has doubled under Neta.

Set against this backdrop and in the context of Ofgem requesting that the initial proposals widen “consumer choice” under the new process—whether it should aggressively pursue cost reductions or act conservatively to manage the system—NG has proposed six alternative, bundled, schemes (*shown in the second table below*). NG stressed at the workshop that these variations could be “mixed and matched”, with caps and collars moved across schemes, sharing factors changed and indexation used.

Proposals for electricity incentive schemes

Wheat and chaff

Scheme	1	2	3	4	5	6
Target, £m	481	495	530	520 to 540	530	540
Upside sharing factor, %	35%	35%	15% from £530 to £520m 40% below £520m	40	35	15
Cap, £m	20	20	10	10	10	7
Downside Sharing factor, %	27%	27%	15% from £530m to £540m 20% above £540m	15	27	15
Collar, £m	20	20	10	15	10	7
Indexes	1. Cheviot Outage weeks 2. Power price option (a)	1. Cheviot Outage weeks	None, but could be added	None, but could be added	None, but could be added	None, but could be added

At this stage Ofgem’s decision to stick with a one-year scheme for 2008-09 is right given the scale and multiple dimensions of the uncertainties that NG faces. In terms of the new process more information is clearly an enhancement, and NG has actively sought engagement across the market, and it is to be complimented for that, especially given the compressed timescales over which it has been asked to carry out the consultation. And, if the process to be repeated for future years, the timetable will need to be brought forward as it is hard to see Ofgem taking a fundamentally different line to that which NG recommends in the remaining time available.

But the overwhelming conclusion is that we are only better informed of the uncertainties and the risks facing the SO (which is not to knock the value of this new information). Setting aside new factors and

risks, it is hard to say whether more efficiencies could have been found in the £399mn proposed baseline for 2008-09, which represents only a £1mn reduction over the current year, and whether there are offsetting savings from the new costs NG considers will be incurred.

Of course there are unknowns over the impact of LCPD, the rate of development with regard to new connections in Scotland and also modelling difficulties linked to generator behaviour and losses. All these factors are scarcely new and their on-set well-trailed, and it would be interesting to know whether Ofgem and its own consultants have undertaken their own sensitivity analysis, and what other parties make of these developments. But the treatment of these in the analysis is to deal with them in isolation. While there are undoubted risks and uncertainties from all these factors, there will also be a diversity effect that should mitigate the additional costs identified that does not seem to have been taken into account. It is also unrealistic to expect NG to be anything other than be very prudent and expect, if not the worst, then far from the best outcomes.

The extent of the uncertainties and the paucity of knowledge in the wider market in our view strengthen the case for unbundling of the incentive scheme. Different cost elements have different drivers and the interactions between them are still not well understood. One element of this complexity is illustrated in the indexation proposal on power prices, whose effects on balancing costs are felt in a number of ways. NG has proposed two indexes for the schemes which would adjust the target to remove some elements outside SO control, one against power prices, and one against the number of Cheviot outage weeks. The concept of a formal revenue driver in areas where the costs are outside NG's control is clearly right, but what is missing perhaps is the extent to which NG is already protected to a degree from such changes by its current suite of contracts and options, an area where the initial proposals are extremely light.

We remain concerned that more is not being done to address transmission constraint costs. These have been increasingly problematic for several years and clearly require treatment either as a separate element of the incentive scheme or outside of it. It is also clear that much more transparent and effective arrangements are required with transmission operators in order to better manage outage plans and to revise them in response to short-run costs. The holy grail of transmission regulation—developing an appropriate relationship between short-run operating costs and long-run investment—remains lost in our system. In essence the current arrangements in GB do no more than permit pass-through of transmission constraint costs based on prudent estimates from a very high base. In the event the problems abate or turn out to be materially less than NG fears, the company would be left with significant windfall gains, which is not in anyone's interests.

More generally the institutional arrangements for transmission constraints have not evolved since Neta go-live, and there have been a number of indications during the current year that some parties have been able to adjust their operating behaviour in a way that has aggravated constraint costs to the wider market but to their own benefit. Access arrangements that assume an unconstrained grid and allow generators to run when they wish or be compensated at levels that do not reflect reasonable costs are simply wrong, and a significant level of costs now seen by NG arises because the flexibility mechanism represented by the Balancing Mechanism is in effect an inflexibility market where often it is a distressed purchaser. We would have expected either National Grid to bring forward proposals for change by now or Ofgem to have hinted at the direction of change, which is now very necessary. In the meantime, the only prudent course is to carve constraints out of NG's incentive arrangements.

Alarming BSUoS remains a rising and unhedgeable cost to the market. In no year has the outturn been close to the forecast, and another overrun is expected this year. But these increases do not necessarily mean equal misery to all grid users. The effect of variation is amplified for one-sided players. Independent generators cannot pass this cost through to a supply business and do not have *de facto* captive customers who are thus exposed to any overrun against their energy contracts. Small suppliers typically use a flat forecast and have also been exposed to any overrun, and they do not see any of the additional revenues being earned by some generators through higher balancing service or mechanism payouts. It is therefore disappointing that NG has not given thought to how it might fix the charge within year, perhaps through hedging the costs it incurs itself by insuring any differences or by year-on-year adjustment factors. We asked them to consider this in November, and would now ask Ofgem to do the same.

As for the options on the table we consider that levels of incentive for the scheme currently under consideration, with a £10mn ceiling as in the current electricity scheme, represent a reasonable upside for *genuinely good* performance (bearing in mind NG already earns a regulated return on the assets employed through the internal aspects of the scheme), though risk and reward should be symmetrical. This inclines us towards option 3, but with a dead-band approach (a fixed single value suggest a level of precision in the forecasting process that NG admits is not achievable) and shifting this back say £10mn to reflect an inevitable negotiating premium in the initial proposals. The use of risk mitigation indices to deal with change in power prices and the time taken to manage outages as per option 1 should also be included.

Missing ingredients

The range of the forecasts, and the extent of the uncertainties which they reflect, reinforces the case for considering changes to the governance of the revised arrangements and in their transparency. In particular, as we have previously argued, there should be more routine reporting within year, including a monthly written report on the year-to-date position against target(s), full-year IBC and BSUoS forecast updates and an operating report embracing all of NG's balancing activities with a commentary on performance, amongst other things, being made to the market. We consider that there is still a long way to go before market reporting is fit for purpose.

And we would like the settlement for 2008-09 to incorporate performance measures and indicators. Given the lateness in the process possibly the most that can be achieved here is for NG to commit to developing this approach for 2009-10. In future years we would then wish to see a form of service level agreement established incorporating explicit targets. This type of framework will be essential if longer duration incentives for particular costs with known drivers are to be developed in a way which allows market participants to have a fair and informed negotiation with NG.