Policy response prompted by questions from DG ENER

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EPRG was requested by DG-ENER to provide briefing on the extent to which the Target Electricity Model would deliver the efficient, secure, sustainable and affordable integrated electricity market in the EU, and if not, what might be needed to improve the situation. This briefing was part of the preparation for a change in the DG ENER Commissioner in 2014.

In response EPRG held a workshop in Cambridge on Friday 10 January 2014, details of which are posted on our web site at http://www.eprg.group.cam.ac.uk/eprg-dg-ener-workshop-9-10-january-2014/ together with presentations. DG ENER sent a set of questions that they wished the workshop to address, and this note is written as a response to these questions. It reflects the views of the author alone, and was my contribution to the workshop, but I am grateful to colleagues for their constructive comments, some of which I have incorporated into this revised text.

1. Is the current market pricing method capable of delivering credible investment signals?

This question as it stands is clearly country specific, as Britain, the Single Electricity Market (SEM) of the island of Ireland, Spain, and the Nordic markets all have different market designs, some with energy-only markets (Nord Pool), some with central dispatch (SEM, Spain), some with or contemplating capacity payments, and some with audited short-run marginal cost bidding (SEM). The Target Electricity Model (TEM) contemplates an energy-only market with self-dispatch and a central auction platform (Euphemia) to couple interconnectors and deliver zonal prices day-ahead, intra-day, and eventually, for balancing. The onus is on any country wishing to implement a different market design to justify departures from this model. The natural starting point is therefore the TEM as contemplated, to see whether it is capable of delivering credible investment signals.

1.1. Is the Target Electricity Model capable of delivering credible investment signals?

To clarify, in this section the investment needed is the efficient choice of durable ***generation*** capacity that will meet the various public objectives of decarbonisation (2020, 2030 and 2050 targets) and the 2020 Renewable Energy Supply (RES) targets. The policy environment includes not only the TEM, but also the EU Emissions Trading System (ETS) and the Renewables Directive. Investment in domestic transmission and distribution networks are devolved to the National Regulatory Agencies (NRAs) of each Member State (MS) and it is their responsibility to choose regulatory incentives to deliver the efficient level of investment. Except for the political problems of resistance to locating high tension grids, they seem to be able to do so. For electrically isolated MSs like GB and Ireland (connected only by DC links) their network investments have no obvious impact on other MSs and so their choice of regime should be devolved to the respective NRAs. Their network charging regimes may impact on the economics of interconnectors and so have EU-wide impacts, as will their mode of supporting interconnector investments. Within the Continental AC meshed network all transmission decisions have EU-wide repercussions and these are addressed via ENTSO-E and ACER and will be addressed in the next section dealing with market coupling.

The first and most obvious problem of leaving generation investment decisions to the current (TEM) market is that the carbon price delivered by the EU ETS is too low at present, and more to the point, its expected future level is also too low and not backed by a credible investible commitment. Whereas investors are happy to take commercial decisions based on their view of future market conditions when these conditions are determined by the free play of commercial decisions of supply and demand, future carbon (and electricity) prices depend on future political decisions that are perceived to be vulnerable to short-run political manoeuvring and hence lacking in credibility. Absent an adequate, durable and credible carbon price, investment decisions will be delayed or distorted. The clean dark spread (for coal-fired generation) is now high (€20+/MWh) compared to gas (€2+/MWh), and almost all low-carbon generation is unprofitable without subsidy. The failure of the ETS that is behind such outcomes provides clear evidence that the market as currently structured cannot deliver the desired generation portfolio.

A related issue is that policy uncertainty and the lack of credible policy commitment devices (such as long-term contracts) will likely lead to delays in investment decisions until the policy landscape becomes clearer, risking, in some MSs, a potential security of supply problem.

A further issue is that wholesale prices are below Long-run Marginal Cost (LRMC) in many MSs as a result of adequate reserve margins and almost fully depreciated generation assets, so that prices would have to rise in any case to induce unsubsidized conventional investment. While wholesale prices are probably too low, retail prices are in many cases too high as a result of high charges for Renewable Electricity Supply (RES) and other environmental policies.

A further expressed concern is that if wholesale markets are competitive then they would set the System Marginal Price (SMP) at the short-run marginal cost (SRMC) plus an element for security of supply[1] up until the price reaches the rationing price set by the demand side. As the variable cost may be only one-third to two-thirds the average total cost, there are concerns that competitive wholesale markets will fail to give adequate investment signals. This would indeed be the case if the SMP were systematically below the LRMC, but not if the normal conditions of competitive markets prevailed. That would require:

- the market is unhindered from reaching efficient scarcity levels with no price caps, up to the Value of Lost Load (VoLL);
- investors have complete confidence that this is the case and that there will be no political or regulatory intervention that departs from this assumption;
- specifically that any market power monitoring or reference to the competition authorities will be able to accurately distinguish between scarcity pricing and market manipulation, which investors may also doubt.

Absent these conditions, and in a world where new investments are more durable, have higher capital cost, and often take considerably longer to commission than the Combined Cycle gas Turbines (CCGTs) of the last dash for gas, investors will either delay until scarcity prices prevail, or until offered contracts that substitute for these future missing markets. One such contract is a reliability option that allows the System Operator (SO) to set a price cap below the VoLL in exchange for an up-front payment, with penalties for non-availability when the price reaches the cap and the option is called.

1.2. What are the main market failures and their solutions?

It follows that one of the main market failures is the lack of sufficiently distant forward markets and/or long-term contracts on which to secure investments. This is related to the lack of credible instruments to address the underlying market failures of an inadequate carbon price that would deliver the required electricity decarbonisation trajectory, and of a mechanism to support research, development, demonstration and deployment (RDD&D) of less mature low-carbon generation options such as RES. Specifically, there is no credible forward price trajectory for carbon prices and little clarity on the extent and nature of future market interventions to support various objectives such as nuclear, renewables, security of supply, etc.

Both climate change mitigation and RDD&D are non-excludable public goods that create market failures and require public action for efficient delivery. DG Clima (2014) published *A policy framework for climate and energy in the period from 2020 to 2030* on 22 January. It argues for tighter 2030 carbon targets (a 40% reduction compared to the 2020 target of a 20% reduction from 1990) and intervention mechanisms to stabilise the EUA price. However, its publication had a negligible impact on the EUA

[1] The efficient way to add the security element is through the Value of Lost Load (VoLL) and the Loss of Load Probability (LoLP) as LoLP*(VoLL-SMC)

price, so clearly the ETS remains insufficient to address the climate change market failure.

The Renewables Directive has the merit of making the deployment of RES a Club Good, devolving the task of financing the targets to MSs, and leaving to them the choice of how and what to support. It has the drawback that it lacks adequate or trusted mechanisms to allocate the funds efficiently across MSs to deliver best value, so that each MS chooses the RES that it favours, often in defiance of its comparative advantage. Thus wind power is often located in less windy countries, and solar PV is less sunny climes.

The solution to an inadequate carbon price would require the removal of the huge overhang of surplus allowances in the period to 2020, combined with a credible mechanism to stabilise their price around a rising trajectory (rising at the social discount rate, which might be somewhere between 1-4% real) and at a level where investment in mature low-C generation is commercially viable. An EU Carbon Bank buying and selling EUAs could do that, but is unlikely to be accepted by all MSs, as abrogating their fiscal sovereignty and their property rights in their allocation of EUAs. There is clearly further work to be done here if the ETS cannot be adequately reformed, either by agreeing increasingly stringent emission performance standards for all new plant (tonnes CO_2/MW/yr), or by encouraging carbon price floors for generation for each MS (as GB has chosen).

1.2.1. Reforming the RES targets and the SET Plan

The Commission has three legs to its climate change policy – the ETS to set the price of carbon, the Renewables Directive to create a demand to deploy near-market renewables and thus drive down their cost of market parity, and the Strategic Energy Technologies (SET) Plan to fund R&D and demonstrations of immature low-carbon technologies. The RES Directive at least assures a funding stream to deliver the RES targets by placing the obligation on MSs, but there is no such assured funding stream for the SET Plan.

Both the inefficiency of the RES allocation across MSs and the lack of finance for the SET Plan might be addressed by reforming RES RDD&D support. The RES targets were set with reference to GDP per head and the potential for additional RES. One possible change would be to replace these RES targets with an equivalent financial target (perhaps set equal to the cost of meeting the original RES target with an uplift for extra R&D described below). That money must be spent on a designated set of low-carbon energy RDD&D actions. The support would be justified in terms of the objectives motivating the RES Directive, which would have to be spelled out and agreed. These designated actions would include R&D for very immature but promising technologies (e.g. wave, tidal stream, far off-shore wind etc), and hence address the SET Plan underfinancing. It would also include demonstrations for those where technologies and their costs need to be tested at scale (CCS, possibly biomass, off-shore wind), and perhaps the funds set aside for that could be rolled into the financial targets or provided in counterpart funds from the EU Budget, as with the CCS competition. Finally, it would include the deployment for near-market technologies currently delivered by the RES targets, where deployment leads to learning-by-doing economies of scale (on-shore wind, solar PV).

The objectives and technology readiness would determine the optimal method for finance. For immature technologies EU-wide competitions are probably best, for demonstration plant tender auctions, and for near-market technologies, tender auctions for feed-in tariffs for MW of available capacity. (The argument here is that for mature technologies like on-shore wind the benefits of cost reduction come from the investment, rather than the operation of the plant, and so the output should just be rewarded at its market value not some multiple of that.)

The credit that each MS would receive for its actions would be suitably benchmarked, so that for e.g. solar PV, it would be credited with an annual value per MW_p based on the extra annual revenue needed to justify installation in a reference sunny location (such as southern Spain compared to a CCGT there). Each MS would be free to offer (and be credited for) finance to support deployment in any location (possibly including approved developing countries, perhaps with a discount as with CERs that can be traded in the EU ETS). Benchmarking would remove the temptation to gold-plate domestic delivery of RES as covert industrial or employment policy) and would encourage optimal location.

Tax payers should pay for public goods like RDD&D and renewables support, not electricity consumers. The reason is one of good fiscal policy design: revenue raising taxes to pay for e.g. public goods should be raised with least distortion and hence exempt the production sector. Discriminatory taxes on a subset of consumer goods (singling out electricity for example) are typically less efficient than uniform VAT (which exempt producers) or income taxes.

1.3. Is a capacity payment needed for adequate investment?

For an energy-only market to operate efficiently, investors would need to be assured of the three bullets indicated in 1.1, or their contractual equivalent. The problem of investor confidence has been complicated by the non-market RES targets that are likely to substantially increase the volume of intermittent zero-variable cost plant on the system, driving down wholesale prices in hours of abundant wind and/or sunshine, but risking shortages when the wind does not blow or the sun does not shine. Intermittent and unreliable generation,[2] such as wind and PV, requires reserve capacity that would run at low capacity factors that would not cover their capital costs without high scarcity prices.

[2] Intermittency suggests predictability but not continuity, such as that delivered by tidal reservoirs, while unreliable is a more accurate description of wind and most solar PV where the hourly output cannot be guaranteed with a reasonable probability months ahead of time.

Even then, the number of hours they could expect to run per year are highly dependent on RES support policy decisions in the future. That might not matter for plant on the verge of exit with very low capital value (the traditional source of peaking reserve) but it does matter where new peaking plant is required, and which would be hard or costly to finance without some form of assured revenue.

Suitably designed capacity mechanisms can reduce the risk and hence the cost of financing an adequate reliability standard. It may be sufficient to only require retail suppliers to secure such capacity for designated customers (e.g. below 100kW) and leave all others to choose whether to receive the default interruptible tariff or a guaranteed secure tariff with a price cap. If so, then reliability options that cap the price in otherwise freely clearing day-ahead, intra-day and balancing markets, extending far enough to underwrite a merchant investment, secured through an auction process, would be sufficient for the below 100kW (say) market, leaving others to contract as they wished. This would require the wholesale price to be free to rise to the VoLL; any price below that would need some form of reliability option or capacity contract to aovid the problem of missing money.

Given that there are a wide variety of capacity mechanisms and that some are clearly compensation schemes rather than directed to deliver security of supply at least cost, DG COMP will clearly be interested in, and will presumably limit, their form. The main design issues of EU-relevance concern their interaction across borders, discussed below.

1.4. *What should happen to windfalls created by market interventions?*

Investors gain if prices move from below up to the efficient LRMC (including the efficient carbon price), just as some lose if e.g. gas prices rise in the wake of the various dashes for gas and reduce profits of CCGT owners, or if nuclear moratoria are imposed at the expense of companies with nuclear stations. Windfalls are often the result of a high perceived *ex ante* risk turning out not to materialise. Examples would include fears of regulatory opportunism gradually being assuaged by consistency and rule-following by the regulator, or a lack of clarity and/or credibility in energy policy leading to high hurdle rates of return (c.f. Hinkley Point), which are then shown to be high when the regulatory/political risk is resolved.

Introducing an adequate carbon price would deliver windfalls to old nuclear stations, and to existing RES supported by premium FiTs, and there could be a case for a windfall levy in such cases, but the (considerable) danger is that to levy a retrospective windfall tax would undermine investor confidence and raise the cost of financing new investment. It would be better to write revenue-sharing arrangements into any future contract that is dependent on a market price or uncertain cost. Such incentive regulation is common for utilities, and has been proposed for merchant interconnectors which might have a cap and floor on the realised rate of return. Market price risk is primarily a problem for premium FiTs and would be avoided by a fixed FiT, but cost-sharing may still be prudent for first-of-a-kind plant.

1.5. Is a regulated utility model cheaper than the capital market? What role can/should Government guarantees play?

There is a case for saying that the regulated utility model can have greater credibility and hence deliver a lower cost of capital for low-carbon capital-intensity plant like RES, nuclear and CCS where they are reliant on what are perceived to be less-than-fully credible political promises, provided regulation is economic and depoliticised. The trade-off is between the discovery role and competitive pressures of markets compared to the risk-reducing role of greater credibility and predictability. An intermediate method of lowering risk and hence cost would be for the Government to act as the counterparty to or guarantor of long-term contracts for investment. If so, then thought should be given to how windfall profits and losses are to be allocated, as poor design could either transfer risk inefficiently to the investor, raising cost, or transfer all the upside gains but not the risk to investors, at the expense of the tax payers. Other intermediate models would include tender auctions with a single buyer (backed by Government guarantees) to reveal the least-cost solutions, which can work well if there are enough potential suppliers who have good but asymmetric information about their development costs.

2. Market coupling and the TEM

Market coupling is a key element of the TEM as it involves improving the efficiency of inter-EU trade. There is a case for clearly distinguishing between actions to improve trade and interventions in MS electricity markets that have no impact on the efficiency of the Single Market and which should be left as devolved MS responsibilities. This is important in contrasting electrically isolated MS such as GB and Ireland, and AC-interconnected MS such as most on the Continent (except Nord Pool).

1.1. Is the Target Electricity Model capable of delivering efficient transmission investment signals?

The EU suffers from inadequate cross-border (interconnector) capacity in that the arbitrage returns for trading across many interconnectors exceeds the cost of providing more capacity at many borders. A key part of the TEM is to first increase the efficiency of existing interconnectors through market coupling, and Newbery et al (2013) shows that this should be worth several billions of euros annually compared with the pre-coupling state. The next step is to ensure that the rest of the meshed continental grid is efficiently used, as any departures from efficiency have impacts on all AC-connected countries. The TEM advocates price zones defined by significant congestion boundaries rather than national borders and this should improve matters, although nodal pricing would further increase efficiency and is discussed next.

1.1. Is the TEM overly influenced by the Nordic design and if so what should replace it? Should we plan on a move to nodal pricing?

The TEM has clearly been strongly influenced by the Nordic Model, on the plausible grounds that Nord Pool has successfully implemented market coupling. However, the Nordic market has adequate capacity and massive storage hydro that greatly facilitates liquid spot and longer-term markets. Arguably one can learn from the U.S. Standard Market Design with voluntary pools and central dispatch, as PJM now efficiently dispatches some 160 GW of generation with inadequate interconnections with a system of nodal pricing (or Locational Marginal Pricing, LMP). Wolak (2011) calculated that a move from zonal to nodal pricing in California lowered energy costs by 2.1% or $105 million per year.

On the issue of central vs self-dispatch there are good arguments for expecting centralized security-constrained unit commitment designs to deliver greater efficiency than self-dispatch with energy only power exchange trading, but it may raise greater incentives for gaming and the exercise of market power, although there are no clear-cut theoretical reasons for expecting that to be the case. Thus de Castro et al (2013) found clear efficiency gains when moving from self-dispatch to central dispatch in Colombia, but found that these gains in productive efficiency were all captured by the generators. This might be rectified with proper market monitoring or perhaps by adding granularity to the bid structure to allow more accurate representation of generators' costs and operating constraints. On the other hand Green (2007) argues that in the case of GB, nodal pricing would have substantially reduced the incentive to exercise market power in the early period of duopoly dominance.

Sioshansi, Oren and O'Neill (2010) simulate the ISO New England market and estimate that self-commitment might raise costs by 4%, which, given the huge value of electricity traded, represents many billions of euros at the EU level. For example, the total value of EU wholesale electricity at €50/MWh is €160 billion/yr, so even with only half the 4% simulated gain, the benefit might be as much as €3 billion per year. Neuhoff et al (2011) provide a back-of-the-envelope calculation suggesting a saving of €300 million per year for a 200-300 GW connected system.

It is not clear that LMP is needed everywhere, and it comes at some cost in market liquidity, but it may also be the least cost option in some MSs, and Poland has certainly actively considered it.[3] However, there are clear challenges in trading between

[3] For a useful discussion of the central questions of LMP vs liquidity see the slide presentations at

unit-dispatched LMP markets and different market designs, and issue clearly identified in the US as the "seams" issue, where improvements in efficiency within LMP markets have come at the possible expense of better integration between zones. De Castro et al (2013) observe that "The literature proposes two solutions to this problem. One is integration of regions into a single nodal pricing region with compatible pricing systems and another approach is tighter coordination of nodal pricing in adjacent systems and fuller representation of neighboring networks in the ISOs dispatch and pricing algorithms." Given the distance the TEM is from either central dispatch or nodal pricing this is an issue for the future, but if some countries decide to move faster towards the US Standard Market Design the "seams" issue may need consideration rather sooner.

1.2. Might market coupling lead to perverse incentives?

In the absence of nodal pricing, Power Exchange (PX) prices may be a poor indicator of the value at the interconnector nodes, and in the absence of efficient locational charging for the grid, interconnectors can easily be mis-located. There is growing evidence that zonal rather than nodal pricing can amplify market power (via the inc-dec game that requires expensive redispatch), and it is hard to accurately define the transfer capacity of an AC interconnector without clear information about the location of generation and load and knowledge of the topology of the grid. Whether these problems are sufficiently costly to warrant a major market design is an empirical issue that needs quantification, and ENTSO-E has already started that in the ENTSO-E (2014) *Bidding Zones Review Process*.

1.3. How should interconnector capacity be (re)calculated, released and priced intra-day?

This is not too much of a problem with LMP and central dispatch as in PJM, but otherwise capacity can be recalculated closer to real time with better wind and PV forecasts and a full knowledge of dispatch plans and demand forecasts, and then the new capacity should be auctioned in a way that encourages efficient trading. That will be facilitated by periodic intra-day auctions that would require suspension of any continuous trading activity.

1.4. How should capacity markets interact with energy-only trading?

Provided the capacity markets deliver efficient short-run scarcity prices and primarily serve to provide longer-term risk hedging (options can do this) there should be no

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http://www.hks.harvard.edu/hepg/Papers/2012/Cusenza_Paul.pdf and http://www.hks.harvard.edu/hepg/Papers/2012/Klein_Abram.pdf obvious problem, except for the difficulty of providing firm capacity ahead on undersea DC links. That said, poorly designed capacity markets that do not give efficient short-run price signals can lead to inefficient cross-border trade. It would seem, but needs to be explored, whether good market design would drive out bad or vice versa.

One important issue is to define eligibility for offering capacity located in one MS to any tender auction or the like in another MS. This would seem to be desirable to reduce the costs of providing reserves, but would need to be deliverable to the location paying for it, which would need some reservation of interconnector capacity. This would require careful design of the capacity contract, including penalties for non-delivery, and of the transmission rights and their penalties for non-availability.

2. How should renewables be integrated into the market?

Ideally renewables should be efficiently located within and between MSs, and efficiently dispatched and remunerated. Some suggestions of how this might be expedited are discussed above, but one could also argue that it should be left to MS as a matter of subsidiarity to decide how to support and integrate their RES. One obvious complaint is that the form of subsidy can distort the markets of neighbouring countries (wind in N Germany and Denmark spilling into Poland and other countries, congesting their interconnectors and disrupting their internal optimal dispatch), but market distortions are a matter for DG COMP, and more immediately a better design of market coupling.

Fig 1 below (from ENTSO-E. 2014), shows the Scheduled (in blue) and Physical (in green) flows in 2011-12 from ENTSO-E (2014) clearly indicating some of the probable effects of this increased wind power in the North. The same source shows that real-time unscheduled flows are equally large and problematic.

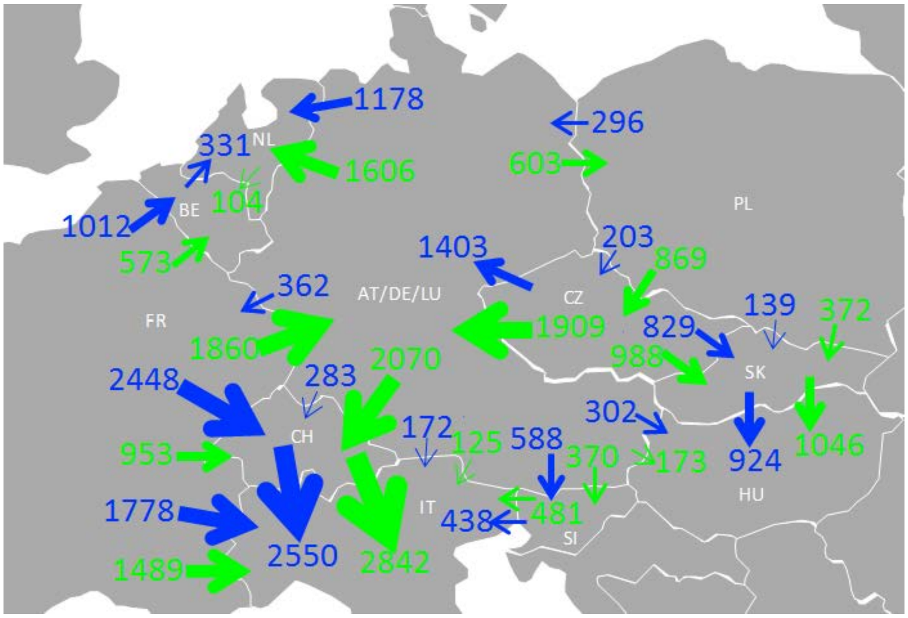

Fig 1 Scheduled and physical flows 2011-12

2.1. Should REScontinue to enjoy priority dispatch?

If, as is desirable, RES are to be efficiently dispatched and priced it may be cheaper to constrain them off than some thermal plant. The issue is primarily how to compensate them in this situation and the logical answer is via a suitable long-term contract price for availability. This might emerge in efficient negotiations over the costs of connection to the relevant network (grid or distribution), where the developer might be willing to accept a less firm connection at a considerably reduced cost. Trials of such contracts are being conducted by Ofgem under its Low Carbon Network Fund competition.

2.2. How should RES be supported and for how long?

Support should be targeted at the desired objective, which for mature low-carbon technologies is increased deployment to drive dynamic economies of scale and lower cost. That suggests that they should receive an availability payment and a carbon price addition to the marginal fossil fuel price, overlaid with contracts for intermittent power that cannot control its output. The support length should be such that together with the form of support it minimises the social cost to the tax payers, which might mean largely upfront with penalties for non-availability and a FiT set at the expected value of electricity (including the correct carbon price). (Immature renewables and CCS at the demo stage need a different approach.)

2.3. Who has to be competitive with what?

If support were measured by benchmarked efficient technology-specific subsidies, all RES could compete with everything else, and the subsidies ought to be payable to whoever can deliver the objective at least cost, with delivery of the RES objectives measured by benchmarked contributions, as discussed above.

2.4. What role can the market play in their support?

The main decision is not whether or not to run but where and what to build and that can be guided by price-like instruments such as efficient grid charges and/or LMPs overlaid with contracts, secured through tender auctions where there are adequate numbers of participants.

2.5. Variability – nuclear and renewables: two sides of the same problem?

Nuclear power is controllable (technically but not necessarily economically) and provides base load, so is good for security of supply. Most renewables (except for biomass and storage hydro) are intermittent/unreliable and can only be regulated down (which can be valuable). They do not fit too well together as intermittent power needs flexible net-demand-following capability, either through peakers, interconnection or storage (which is the rough order of cost) rather than load-following by nuclear power.

2.6. Carbon – Is ETS the answer? And if so what is the correct question and right answer?

The right question is how to deliver credible investment signals for very durable low-C generation (and reduced emissions generally) and the current ETS fails to deliver that. Reforming the ETS to deliver a predictable, credible and durable rising carbon price is first best, failing which a carbon price floor (ideally EU-wide, failing that some minimum coalition of the willing) supplemented by contracts, failing which an emissions performance standard (tonnes CO_2/MW capacity/year). In thinking of the 2030 objective the main point is that after 2020 we should know what low-carbon makes sense and thereafter ensuring that there is no unabated coal and that the sole target is lower carbon, with everything else left to a better designed technology support system. The DG Clima (2014) document proposes abandoning country-specific RES targets while retaining them at EU level, which might encourage a more efficient allocation and support mechanism. Disappointingly, the document has no effective solutions to the large surplus of current EUAs, so the carbon price remains far too low to encourage market-led low carbon investment.

3. What of the future?

Some commentators have voiced their concerns that the thrust for market liberalisation has outlived its purpose, which was to make better use of existing capacity, and that it is not well-suited to delivering new capacity, unless that is low capital-cost fast-build cheap gas in the form of CCGTs. If the complaint is that new investment in capital-intensive plant appears to need a long-term contract, it should be remembered that liberalisation in Britain led to a “dash for gas” and high investment in new CCGTs, despite no problems with capacity adequacy, but that all the new entrants financed these CCGTs on the back of 15-year Power Purchase Agreements, without preventing the wholesale market delivering (reasonably) efficient dispatch.

3.1. Is the IEM fragmenting as balancing, capacity and support mechanisms become increasingly important and if so what is the way forward?

This is clearly a danger of individual MSs choosing a variety of solutions that may not be very compatible for efficient cross-border trade. Where their choices do not have any efficiency impact on cross-border trade there is a case for devolving the choice to the MS, but otherwise the way forward is greater congruence of instruments and objectives, such that prices reflect social costs and benefits, in which case trade can be left to deliver remaining benefits. The real question is whether, as seems plausible, good market designs and efficient pricing drives out bad, provided DG COMP comes down of market manipulation including subsidies that inefficiently protect local industry.

3.2. What might be the outcome of the Energy State Aids consultation?

The principles are sound but the risk is that the exact drafting will be interpreted legally and that may lead to perverse outcomes that will undermine particularly second-best support schemes.

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