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Electricity – Social Service or Market Commodity?

The importance of clarity for decision-making on nuclear build

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INTRODUCTION

The oncoming government in the UK has inherited an electricity supply system at a crucial point. There have been perhaps two phases in the development of electricity supply since the liberalisation and privatisation of the early 1990s – the 'dash for gas' (roughly 1990 to 2000) which saw major investment in a new technology, Combined Cycle Gas Turbine (CCGT), designed in view of some commentators to reduce UK dependence on domestically-mined coal, followed by a decade on which very little new capacity of any description has come on line, as older power stations (notably coal and nuclear) come to the end of their economic lifetimes, so there is a growing need for new investment in generating capacity over the next two decades.

Yet there is a serious question over the clarity of the new government's approach to electricity generation, as there was with its predecessor. This is especially the case with regard to nuclear energy, where the two coalition partners entered the 2010 General Election with very different policy stances, the Conservatives being largely in favour of a new nuclear energy programme, the Liberal Democrats being against, an issue heightened by the appointment of a Liberal Democrat to the position of Secretary of State for Energy and Climate Change. In the coalition agreement the matter was dealt with as follows:

> Liberal Democrats have long opposed any new nuclear construction. Conservatives, by contrast, are committed to allowing the replacement of existing nuclear power stations provided they are subject to the normal planning process for major projects (under a new national planning statement) and provided also that they receive no public subsidy.
>
> We have agreed a process that will allow Liberal Democrats to maintain their opposition to nuclear power while permitting the government to bring forward the national planning statement for ratification by Parliament so that new nuclear construction becomes possible.
>
> This process will involve:
>
> - the government completing the drafting of a national planning statement and putting it before Parliament;
> - specific agreement that a Liberal Democrat spokesman will speak against the planning statement, but that Liberal Democrat MPs will abstain;
> - clarity that this will not be regarded as an issue of confidence[1].

However, the rest of the energy and environmental policy published by the coalition government, while promising some new approaches in detail, maintained the broad direction of that of its Labour predecessor. 'We will reform energy markets to deliver security of supply and investment in low carbon energy, and ensure fair competition.'

[1] http://www.conservatives.com/News/News_stories/2010/05/Coalition_Agreement_published.aspx, Conservative Party (2010), *Conservative Liberal Democrat coalition negotiations – agreements reached 11 May 2010.*

Once again there seems to be a fundamental lack of clarity as to whether electricity is to be delivered by a competitive market, or whether government will intervene on a regular basis to ensure, or seek to ensure, the delivery of a series of social and industrial goals. This paper will argue that a 'middle way' on this issue would be worse than a purer stance, be it either that electricity is a commodity to be delivered in a stable marketplace or a social and industrial service to be delivered through central governmental direction.

'Decisions' over issues such as nuclear energy are bound to be complex. Inevitably the input information will be vague and imprecise, in areas such as:

- the projected demand for electricity in the geographical area in question and extent to which this demand might be satisfied by imports or must be generated locally;
- the economics of various alternatives (fuel prices, effectiveness of project management, decommissioning and waste management costs, prevailing rates of return and inflation, economies of scale for different sized programmes, effects of regulatory change);
- security of fuel supplies (geographical, geopolitical, infrastructural);
- related technological advances (carbon capture and storage, 'the hydrogen economy', new technologies such as fusion);
- political and social factors (changes of government, change of policy as a result of accident elsewhere or referendum, direct action campaigns, legal action);
- environmental effects (accuracy of lifecycle emissions estimates, severity of climate change, costs associated with climate change, European Union Directives, severity and associated costs of other environmental issues including the effects of accidents).

To an extent, uncertainties of this nature can be managed by a scenario approach which, in principle, might deliver a probabilistic assessment of the likelihood of say a nuclear new build policy delivering against clear success criteria.

However, these success parameters themselves for such a policy decision may be far from transparent. Even if one accepts that there are four requirements of energy policy, viz:

- economic acceptability;
- security of supply;
- environmental acceptability;
- social and political acceptability;

It is at least as much a matter of personal values and judgment as of fact and formula to decide how to balance these requirements. With some individuals or organisations, for example, there seems to be a visceral hatred of nuclear energy (which might be broadly located in the fourth requirement category above) which either overrides any other consideration or leads the individual or organisation in question to interpret the arguments for nuclear energy on economic, supply security and environmental grounds as negatively as possible. (Others show a mirror-image zeal in their unblinking support for nuclear energy.) For others economic considerations outweigh the environment, perhaps driven by (or alternatively driving) scepticism about climate change. Others feel the civil liberties implications of nuclear security are serious if not unacceptable; others still have no such reservations or are even attracted to 'strong' centralised governments.

Such matters are perhaps most effectively addressed through the political system, as guardian of society's values and ethics (or at least the most credible locus for such deliberations). However, the timescales involved in nuclear investment – a new reactor applied for today might well still be generating electricity in 70 years' time – will span several political cycles. A decision on new build today is to an extent a decision on the use of nuclear energy in say 35 years' time. 35 years ago nuclear energy was benefiting from perceptions of limited availability and high prices of alternatives in the wake of the oil shock of 1973 and investment was made almost exclusively within vertically integrated electricity systems characterised by geographical monopolies of generation (with concomitant duties to supply). Within 20 years several countries had adopted moratoria on new build and in some cases phase-out programmes, many reactors and other nuclear facilities having been closed or planned for closure for non-economic or technical reasons. Even where no policy of this kind was adopted, the shift from a command-and-control paradigm of electricity supply to a competitive model left several investors with 'stranded costs' of plants, built on the assumption that captive customers would perforce pay off the costs of such investment, now having to make their way in a liberalised marketplace and compete largely on a marginal cost basis.

There is however a third level at which clarity of decision-making can be threatened, that of responsibility and accountability. In whose benefit is a decision on, say, nuclear new build taken – or to put it another way, who will carry the can if the policy fails to deliver on its perceived objectives, perhaps most crucially in terms of 'keeping the lights on'?

TWO PARADIGMS

As noted above, it is possible to characterise two broad approaches to electricity supply – ‘command-and-control’ and ‘liberalised’[2].

In reality the walls are permeable. In the UK, which has one of the most liberalised electricity markets in the world, there are and have been clear command-and-control instruments in place, such as renewables targets (some as a result of European Union Directives), the 1998 moratorium on new gas-fired connections, subsidies for exploration and State insurance against major nuclear accidents. The new coalition government in the UK talks of specific measures to promote or discourage investment in particular fuels, e.g. an increased target for renewable energy in general and support for a major expansion in offshore wind power in particular. Similarly within command-and-control models there are often competitive tendering aspects, for example for plant construction contracts.

Nonetheless, there are fundamental philosophical differences, driven at least in part perhaps by political fashion as well as by perceptions of the main threats to and priorities for outcomes[3]. Broadly speaking, command-and-control models may be more appropriate at times when security of supply is perceived as under pressure(and perhaps, though less straightforwardly, when there are pressing environmental requirements), while liberalised markets may deliver higher levels of economic efficiency (though not necessarily lower prices) at times when energy security looks robust.

Yet despite the liberalisation of electricity markets, governments in many countries seem in practice to have remained undecided, or even confused, as to whether electricity should be regarded fundamentally as a commodity (requiring minimal government intervention in the marketplace beyond the measures required to prevent unfair competition and the internalisation of economic externalities such as environmental effects) or as a social service (requiring government to intervene in or even control delivery systems in a more fundamental way). The dichotomy is made sharper by unique features of electricity, notably the fact that practically speaking it cannot be stored in large quantities. This confusion leads to inconsistencies in policy which serve to deter private investment without necessarily delivering the social goals that governments require. This is especially the case with the more heavily capital-intensive energy sources such as nuclear power, which inevitably face longer payback periods and hence *prima facie* higher levels of economic risk.

The implications for decisions over nuclear new build are fundamental – as fundamental as asking who will actually take such decisions. Sometimes the previous

[2] A liberalised approach of course does not, or need not, imply no State or regulatory intervention. Regulation is still essential to prevent or curtail unfair business practices, especially given the high capital barriers to entry into electricity generation, and to value economic externalities, most notably perhaps in the field of pollution.

[3] For example, in a command-and-control system emission reduction is usually done by imposing reduction targets on the main (or only) generating company, while in a liberalised model market instruments such as taxes and/or tradable emission permits appear to sit more comfortably, the former giving a predictable price, the latter (in principle) a predictable outcome. There are examples of successful outcomes of both of these approaches, for example in reducing sulphur emissions (by targets in the UK and through tradable allowances in the USA), though it is claimed that market measures deliver both a more cost-effective solution and promote innovation and going beyond the minimum required reductions, though perhaps at the expense of certainty of outcome, at least in the case of pollution taxation.

UK government spoke as though it had decided that new nuclear stations would be built:

> 'The Government has today concluded that nuclear should have a role to play in the generation of electricity, alongside other low carbon technologies[4].'

At other times it made it clear that this was not a decision for government at all.

> 'It would be for the private sector to initiate, fund, construct and operate new nuclear plants and cover the costs of decommissioning and their full share of long term waste management costs[5].'

Though not with reference to nuclear in particular, some of the statements of the new coalition government seem to reveal a similar ambivalence, with talk both of making the market work and of promoting particular technologies such as offshore wind energy and energy from anaerobic digestion of waste.

It can be argued, then, that governments must decide, and then act upon that decision, as to whether they are prepared to let competitive electricity markets work – in which case the economic efficiency of supply systems should improve significantly but there may be times of difficulty, including very high prices and perhaps even power outages – or will treat electricity basically as a social service and intervene regularly to keep the market 'on track'. The latter does not necessarily imply a return to the days of nationalised monopolies – competition in the supply of social services via say a tendering process is a well-tried model in many economies – RWEbut a more interventionist approach to attracting new investment may be required, possibly including subsidies or reserved market tranches for energy sources with high initial investment costs.

A further complication arises when environmental considerations are taken into account. For example, in 2007 the European Union agreed that 20% of all EU energy should be produced from renewables in 2020, the UK target subsequently being set at 15% (against a figure of 1.3% in 2005)[6]. This would imply renewables generating perhaps 35% of UK electricity in 2020. In the longer term, the UK's commitment to a cut in greenhouse gas emissions of 80% by 2050 would effectively require a zero carbon electricity sector. In a command-and-control paradigm government and its regulators could ensure that reduction targets were met by in effect dictating the fuel mix and other parameters of energy production and use. In principle at least, the same outcome could be delivered within a market paradigm by setting sufficiently stringent levels of tradable emission permits with associated draconian penalties for non-compliance. (Use of taxation, the other main 'market mechanism', is less teleological by its nature, as the market may decide simply to pay the taxes rather than to reduce emissions by the required amount.) However, to rely on a mixture of the two approaches (as it currently the case, there being a mixture of renewable obligations, an essentially command-and-control method, and market measures such as the European Carbon Trading System and the Climate Change Levy) risks sending mixed signals. Command measures may undermine the market for carbon credits, directing attention towards particular policies rather than focusing on outcomes and allowing the market to

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[4] http://www.berr.gov.uk/files/file43006.pdf, BERR (2008), Meeting the energy challenge – a White Paper on nuclear power (foreword by Prime Minister Gordon Brown).

[5] Industry Secretary Alistair Darling, http://news.bbc.co.uk/1/hi/uk_politics/5166426.stm, BBC online (2006), 'Nuclear power plants get go-ahead.'

[6] http://www.euractiv.com/en/energy/eu-renewable-energy-policy/article-117536, 'EU renewable energy policy', Euractiv (July 6 2009).

deliver in the most effective way. If confidence in long-term carbon prices falls this may result in an unwillingness to invest in innovative emission reduction technologies or techniques.

The central argument of this paper, then, is that the present halfway house is worse than either of the command-and-control or market-based options.

The introduction of competition into electricity systems – variously referred to as 'liberalisation' or 'deregulation', though such terms are something of a misnomer[7] – became the predominant trend in the markets of developed and, increasingly, developing countries in the period staring around 1990. Many major organisations, such as the European Union, the Federal Energy Regulatory Commission (USA) and the International Energy Agency have encouraged countries to increase the extent to which both production and supply of energy are open to market forces (while recognising that some elements of the process, notably transmission and distribution, are in effect natural monopolies and must therefore continue to be regulated). The details of liberalisation vary significantly from country to country but most models share some or most of the following features:

- unbundling of the natural monopolistic elements of provision of electricity – basically the wires which carry the electricity – from those elements which are amenable to competition, including generation, supply (i.e. sales directly to the consumer) and metering services;

- to a greater or lesser extent, introducing barriers on vertical integration between generation and supply and also measures to prevent single players winning too large a share of either or both of these subsectors;

- introducing a competitive market in generation, with a range of contracts available in the marketplace;

- bilateral 'over-the-counter' trading;

[7] One particularly area in which regulation may be even more important in competitive markets than in command-and-control systems is that of potential market abuse, illustrated most notoriously by Enron in the California crisis. Clearly a strong case can be made for intervention in real time to prevent such abuse. But this in turn raises fascinating questions as to whether it can ever be possible in principle to design a market which is proof to any war game strategies which unscrupulous (or even just market-savvy) players might dream up, and as to whether periods of high prices necessary to send signals to invest can be distinguished from periods of high prices caused by gaming. If not, this may seriously undermine the philosophical case for markets in electricity production. In the words of a former Chairman of the California Power Authority, following the crisis, 'There is one fundamental lesson we must learn from this experience: electricity is really different from everything else. It cannot be stored, it cannot be seen, and we cannot do without it, which makes opportunities to take advantage of a deregulated market endless. It is a public good that must be protected from private abuse. If Murphy's Law were written for a market approach to electricity, then the law would state 'any system that can be gamed, will be gamed, and at the worst possible time'. And a market approach for electricity is inherently gameable. Never again can we allow private interests to create artificial or even real shortages and to be in control. Enron stood for secrecy and a lack of responsibility. In electric power, we must have openness and companies that are responsible for keeping the lights on. We need to go back to companies that own power plants with clear responsibilities for selling real power under long-term contracts. There is no place for companies like Enron that own the equivalent of an electronic telephone book and game the system to extract an unnecessary middleman's profits. Companies with power plants can compete for contracts to provide the bulk of our power at reasonable prices that reflect costs.' http://web.archive.org/web/20030503201728/http://commerce.senate.gov/hearings/051502freeman.pdf, Freeman S.D. (2002), Testimony before the Subcommittee on Consumer Affairs, Foreign Commerce and Tourism of the Senate Committee on Commerce, Science and Transportation.

- an independent system operator responsible for managing a spot market and dispatching plant in real time;
- competition in the retail market, at least for consumers with large power demands;
- a regulator to oversee such issues as fair competition and mitigation of market power, monitoring of capacity margins[8] etc.

This paper will focus on the competitive parts of the market. As noted above, transmission and distribution systems are generally treated as natural monopolies, with regulation acting as a surrogate for market forces to create financial discipline.

The motivations for liberalisation have varied from country to country, but often include the following:

- easing of the fossil fuel crisis of the 1970s which had seen oil prices quadruple and the emergence of serious fears about security of imported supplies and had led governments to take a high profile in ensuring investment in alternatives such as domestically-mined coal and nuclear energy;
- a need to raise money by privatising State-owned electricity assets, coupled with growing impatience with the drain on public finances that investment in energy infrastructure represented;
- the growing political fashion, with the spread of neo-liberalism in the 1980s and 1990s, for market solutions to industrial issues;
- the recognition that the previous system of monopolies had often tended to be technology-driven rather oriented to the needs of consumers, resulting for example in over-investment in generating plant beyond levels that were necessary to deliver reasonably secure power supplies and in poor decisions on choice of plant;
- pressure from outside or supranational bodies such as the European Union (though the response to this pressure seems to vary considerably from country to country).

The nature of energy systems

It is widely accepted that there are four requirements of energy systems:

[8] Capacity margin, expressed as a percentage, is defined as: Generation capacity - Average Cold Spell (ACS) demand ACS demand. It is generally accepted that a capacity margin of between 12% and 20% is needed to ensure secure power supplies against unexpected events such as a surge in demand, perhaps because of extreme weather conditions, or the unexpected breakdown of a considerable number of generating plants. The precise size of the required margin depends on factors such as access to imports and the fuel mix used for electricity production.

- economic competitiveness – energy, and particularly electricity, is a vital ‘producer good’, in that people do not buy electricity for its own sake but cheap supplies are of vital importance within a range of manufacturing and service industries and hence to the international competitiveness of an economy;

- security of supply – outages of electricity can have serious adverse social and health consequences (looting, loss of vital support systems in hospitals etc) and are enormously expensive, especially if they are prolonged. Calculations suggest that the cost of a ‘lost unit’ to a consumer (Value of Lost Load or VOLL) is in the range of US$ 2,000 to US$ 7,500 per MWh, some 25-80 times the UK wholesale price in 2009[9] (in other words, the damage done to consumers who face a power cut of one unit could cost around 50 times as much as they would have had to pay for the unit at normal prices) and even significant degradation to the quality of the power supply (in terms of voltage or frequency) could have major detrimental effects for some applications, e.g. electronics;

- environmental acceptability – some environmental damage through production and use of energy is inevitable, but the scale of some energy-related problems can be very large (climate change being generally accepted as the most serious example);

- political and social acceptability – a more difficult category to define but which has been enormously important in policy-making in the past and includes such issues as the desire to protect the communities involved in producing a particular fuel, fear of the political power of the trade unions, different views as to the degree of centralisation (e.g. of power production or of decision-making) that is desirable in society, a wish not to offend public opinion, the prevention of ‘fuel poverty’ etc.

The challenge to decision-makers is that these requirements are often in conflict with each other. There are obvious tensions between a desire for cheap energy and requirements to prevent or capture emissions, and between protecting secure supplies say by promoting a large programme of nuclear power stations and keeping some elements of public opinion satisfied.

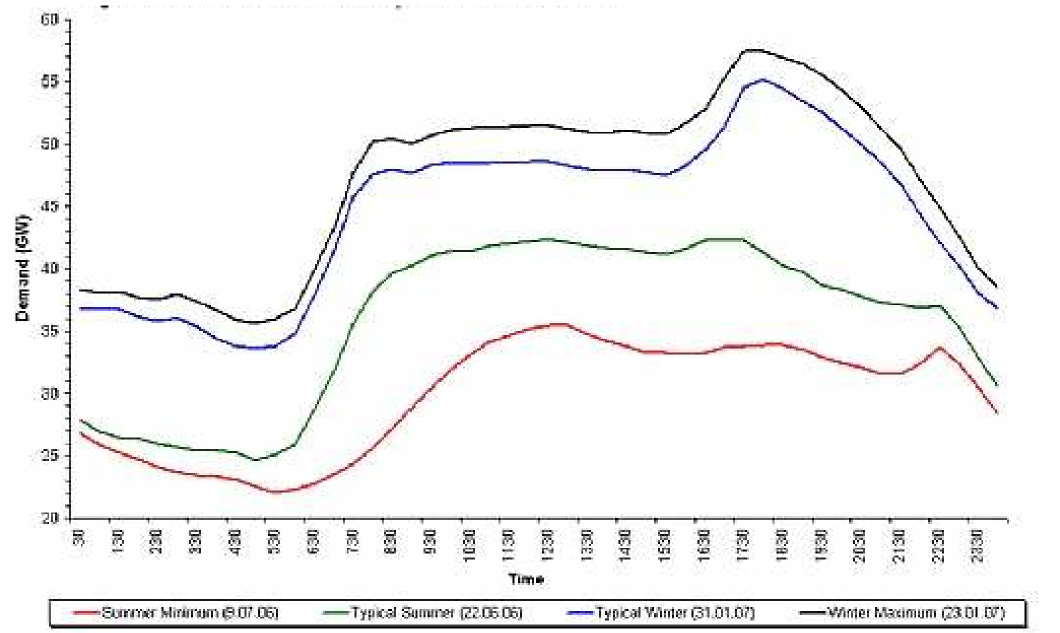
More subtly, some of the above requirements (notably the desire for cheap supplies) imply that electricity is a commodity much like any other and will be best served by a more or less free market, while others, including the desire to maintain secure supplies at an individual household level and to tackle fuel poverty (insofar as this differs from general poverty), suggest that it should be regarded more as a social service.

Two points complicate matters in the case of electricity. The first is that, uniquely among commodities, it cannot be stockpiled in large amounts. In most industries output can be stored for some time, usually at times of low demand and low price, and released when demand rises or prices recover. This cannot be done with electricity

[9] E.g. http://www.nera.com/wwt/publications/5740.pdf, Shuttleworth G. and MacKerron G., NERA (2002), Guidance and commitment: persuading the private sector to meet the aims of energy policy, cites £2,000 (US$ 3,800) per MWh;
http://www.neca.com.au/Files%5CRP_Review_of_VoLL_Dec02.pdf, NECA (Australia), Review of the value of lost load cites A$ 10,000 (US$ 7,800) per MWh.

(notwithstanding two hollowed-out mountains in north Wales). However, demand for electricity varies considerably during the day and during the year (by anything up to a factor of 3).

Figure 1: UK Summer and Winter Electricity Demand (2006/07) [10]

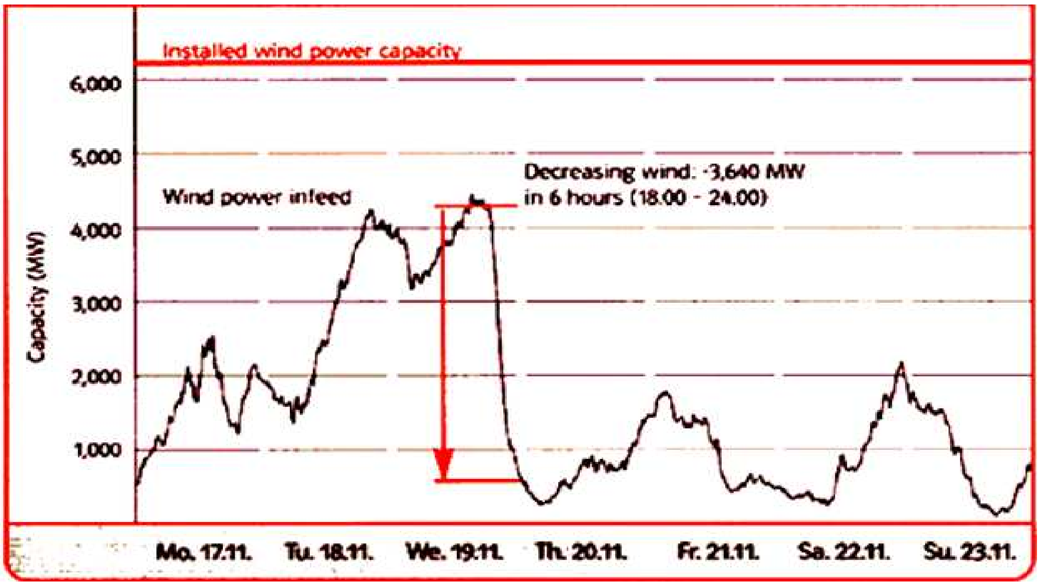


A certain amount of plant (typically with relatively low fixed costs and high fuel and other variable costs) will have to be kept available to keep the lights on at times of highest demand but which will be unable to command a market at other times of year.

This problem is exacerbated if there are significant quantities of intermittent energy sources, notably windpower, on the system. The system must be able to respond to rapid decreases (or indeed increases) in wind speeds, which will render wind generators unavailable – the average load factor of windfarms is about 30% of their rated output. However, when the wind is blowing at appropriate speeds, the owners of the back-up capacity, some of which must be kept ‘spinning’, i.e. ready for immediate deployment if wind output falls rapidly and so using fuel and emitting carbon dioxide, will not be generating value (though the financial system may be organised in such a way as to give ‘hot standby’ payments to such plant as an incentive to keep them available).

[10] http://www.eirgrid.com/EirgridPortal/uploads/Wind%20Dynamic%20Modelling%20Update/7_Chapter%203_Internet.pdf, National Grid Transco (2007), Transmission forecast statement 2007-2013.

Figure 2: Fluctuations in Wind Power Feed in E.On Netz Control Area, Germany, November 2003[11]



This raises a key question – in whose financial interests is it to maintain such plants? Obviously it is in the interests of household (and other) consumers, but who should bear the costs of keeping these plants ready on the (by no means certain) assumption they might be needed for a few hours a year? In principle some generators might keep plant available on the assumption that they can charge extremely high prices at those times of peak demand[12] – it is a feature of the electricity market that the spot price is extremely volatile. Small consumers want the lights to stay on but have relatively little market power acting on their own. Producers, for whom retaining idle plant for use for a few hours per year, if that, is expensive, do not necessarily share the same interest in absolutely secure supplies. If the odd outage, or fear thereof, pushes the price of electricity up significantly then it might be in the producer's interests to allow that to happen. (This disparity between the interests of consumers and producers is wider than in most commodity markets, where the product can be stored and therefore where short-term interruptions in manufacture are less serious.) However, two caveats should be entered.

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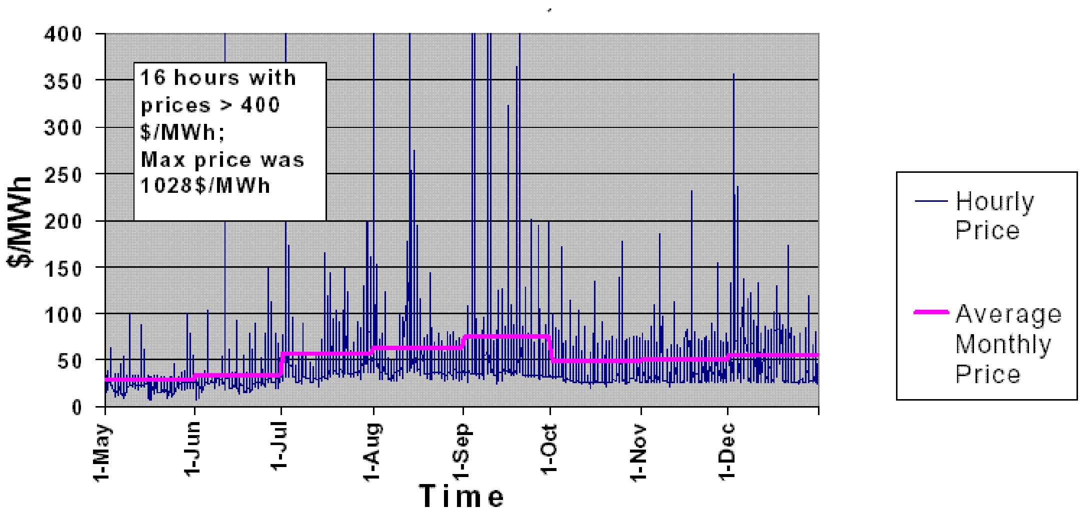
[11] http://www.eon netz.com/frameset_reloader_homepage.phtml?top=Ressources/frame_head_eng.jsp&bottom=frameset_english/energy_eng/ene_windenergy_eng/ene_win_windreport_eng/ene_win_windreport_eng.jsp, E.On Netz, Wind Report 2004.

[12] Plants used for covering peak electricity demand typically carry fixed costs of the order of £20,000 per MW installed. If such plants were only to operate for two hours per year then they would have to command a market price of £10,000 per MWh during that time to cover those costs (against a typical spot price of £25 per MWh for winter 2003/4). Operating for 20 hours would necessitate a price of £1,000 per MWh and operating for 200 hours (e.g. for the two hours of peak demand each day over a three month period) a price of £100. See http://www.nera.com/wwt/publications/5740.pdf, Shuttleworth G. and MacKerron G., NERA (2002), Guidance and commitment: persuading the private sector to meet the aims of energy policy.

Figure 3: Ontario Electricity Market Prices, May 1 2002 – Dec 31 2002[13]



First, a mild winter or an excess of capacity over what was expected (perhaps because a company with its own generating capacity decides to sell electricity rather than run its manufacturing plant) could deprive this peaking plant of a market altogether. This consideration may act as a deterrent to generating companies retaining sufficient back-up capacity for an unusual but not extraordinary winter peak.

Secondly, there is a pervasive perception, based on many examples, that governments, acting as 'guardians of social good', may step in to prevent 'profiteering' on the part of those plants which, for the short time during the year that they do have a market, have to charge tens or hundreds of times their fuel costs in order to cover the fixed costs for the rest of the year. During the California power crisis and its aftermath the State government imposed price caps on electricity sales at seven different levels, ranging from $52 per MWh to $750 per MWh[14]. Perhaps the most striking example of short-term intervention in the UK marketplace, for what appeared largely political reasons, was the moratorium on new gas-fired plant introduced by the then Trade and Industry Secretary Peter Mandelson in October 1998 (statedly to give the government time to reform the market in favour of coal) which was quietly abandoned by his successor, Stephen Byers, in 2000. One can only guess the effect that such apparently unpredictable (if not random) interference has on the financial calculations of the cost of capital and perceptions of economic risk among companies involved in long-term investments.

Such manoeuvres may not be deeply problematic at times of overcapacity in the system, typical of the early days of liberalisation in many countries – the centralised systems that preceded liberalised markets tended to 'gold-plate' security, knowing that they could pass on any excess costs to their captive customers (the resulting overcapacity being one of the drivers for liberalisation in many countries). However, as time goes on, demand rises and older plants come to the end of their operating

[13] http://www.apma.ca/client/APMA/APMA.nsf/09f794f7871969fa852569a100026fab/2335108d49100cf385256b870072c734/$FILE/John%20Lambert.PDF, Lambert J. (2003), Electricity deregulation, the Ontario experience.

[14] Another example of regulation having the opposite effect from that intended that emerged during the California crisis involved environmental regulations in the Los Angeles basin which resulted in closure of some relatively clean gas-fired power stations in favour of older and dirtier plants.

lifetimes, new investment is eventually required, a point which has now been reached in the UK and other markets[15]. The uncertainties both about winning market share at suitable prices, and about volatile interventionism by government or regulators to prevent investors commanding a reasonable return, may serve to deter investment in new capacity in time to prevent the first power cuts. Indeed, while delaying investment carries with it the danger that competitors may steal a march in business terms, the advantages to all players of keeping capacity margins tight and therefore prices high are such that informal cartels may develop even in relatively fragmented markets.

So – can markets be arranged in such a way that the social requirements of electricity are delivered without government interfering to the point that investment is deterred, or are power markets doomed to fail under the weight of political confusion? This question, which would have seemed preposterous a decade ago, today seems rather more relevant.

[15] http://www.berr.gov.uk/files/file39387.pdf , BERR (2007), Meeting the energy challenge – a white paper on energy. 'In electricity markets we will need investment in new generation capacity of around 30-35 GW over the next two decades to replace power station retirements and meet rising electricity demand as the economy grows.' In fact, if electricity continues to penetrate other energy markets such as transportation and space heating the gap between generation capacity and demand could be even wider.

CASE STUDIES

Before considering two case studies of government and regulatory action, or refrain from action, in practice, a caveat should be entered. It is in the nature of issues of such complexity as electricity delivery that it is not possible to carry out controlled experiments, changing just one variable to determine its significance. There is an obvious inherent risk in trying to compare a geographical region comprising four separate countries with a single State within a wider jurisdiction, for example. The economic and regulatory culture in Scandinavia, where the relationships among government, regulators and the public is often characterised as being one of openness and trust, differs from that in the USA, another potentially important contrast[16].

A SUCCESSFUL LIBERALISATION – SCANDINAVIA

In its 2003 report[17] the joint Working Group of the competition authorities in the Nordic region concluded that:

> 'the deregulation of the Nordic electricity sector has been largely successful. The reforms have made it possible to utilise the complementarities of the coexisting different production technologies. In addition, integrating the national markets of Sweden, Denmark, Finland and Norway has decreased market concentration.'

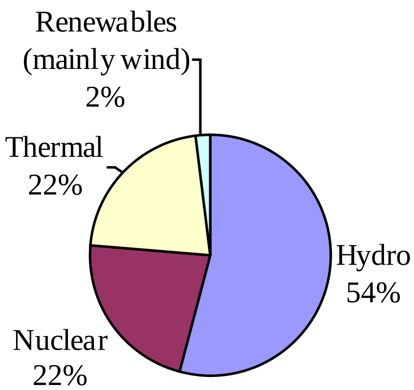
The four countries in the Scandinavian power market, combined population nearly 25 million, have been increasing their degree of mutual cooperation for many years. One result has been that the participating countries benefit from rather wider fuel diversity than would be the case individually (with the exception of Finland, which already had a diverse fuel mix). In 2007 the proportions of electricity generated were as follows[18]:

Table 1: Energy generation in Scandinavia, 2007

	Electricity generation (TWh)	Fossil fuels ('thermal')	Nuclear	Hydro	Other (mainly renewables)
Sweden	145	10%	44%	45%	1%
Norway	137	1%	0%	98%	1%
Finland	78	53%	29%	18%	0%
Denmark	37	81%	0%	0%	19%
TOTAL	398	22%	22%	54%	2%

[16] See for example Miller, A. H. and Listhoug, O., (1998), 'Policy preferences and political mistrust: a comparison of Norway, Sweden and the United States', Scandinavian Political Studies, 21, 161-187.
[17] http://www.ks.dk/publikationer/konkurrence/2003/kraftmark/, Nordic competition authorities (2003), A powerful competition policy.
[18] http://195.18.187.215/docs/1/FNNNANPANOOINEFNMELIPAIEPDBW9DBY7G9DW3G71KM/Nordel/docs/DLS/2008-00299-01-S.pdf, NORDEL (2008), Annual Report 2007.

Figure 4: Electricity Production in Scandinavia, 2007



In a wet year hydropower produces cheap and flexible power, in a dry year thermal and nuclear can be more reliable.

Liberalisation in Scandinavia has proceeded at two levels. Each of the individual countries has liberalised its national power production markets while at the same time building on the pan-Scandinavian cooperation which has developed over some decades.

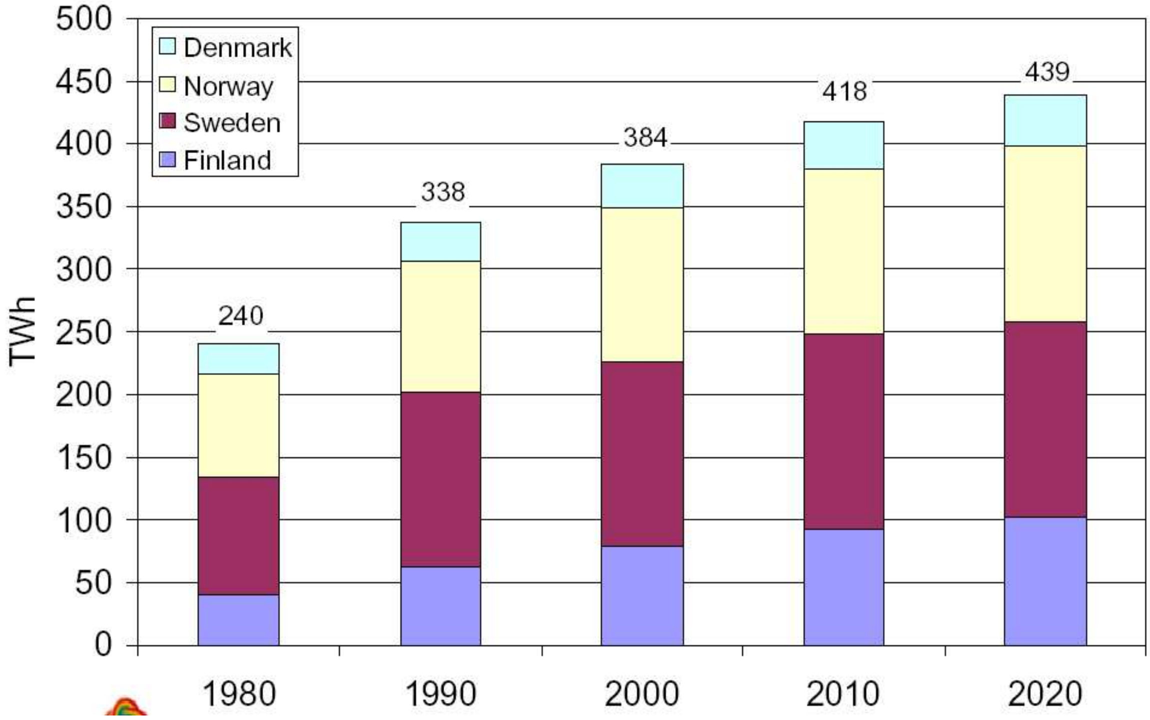
Norway was among the first countries to liberalise its electricity system, a competitive market being established in 1991 and fully operational in 1992. Subsequently Sweden (full deregulation in 1996), Finland (1998) and Denmark (2000) have joined Norway to form a regional electricity system in which there are no institutional national barriers to trade.

The impetus and reasons for liberalising and restructuring have varied from country to country. In Denmark, for example, there has been less of a desire to reform present market structures, other than to accommodate changes in the European Union and the Nordic developments. Finland, which already had a diversified power structure, has become more involved as links between Norway and Sweden have strengthened. In Norway, electricity costs were seen as high relative to what should be achievable with such considerable hydro resource and investment decisions were not always optimal. In Sweden, the introduction of competition into the electricity industry (and many others) was seen as part of a programme aimed at helping the country out of the economic stagnation into which it had fallen in the late 1980s.

Electricity demand in the region has grown steadily, and is expected to continue to do so[19].

[19] http://www.energia.fi/attachment.asp?Section=467&Item=3268, Finergy (2003), European Electricity Market Perspectives.

Figure 5: Electricity demand in Scandinavia, 1980-2020



On the face of it, the balance between generation and consumption has remained relatively steady through the period.

Table 2: Electricity production in Scandinavia, 1990-2007

Production (TWh)	1990	1996	2000	2007
Denmark	24	50	34	36
Finland	52	66	67	78
Norway	120	104	143	137
Sweden	142	137	142	145
TOTAL	338	357	386	409
DEMAND	338	360	384	412
NET IMPORTS	0	3	-2	3

The major players in the Scandinavian power generation markets (2005) were Vattenfall (Sweden, 90 TWh), Fortum (Finland, 51 TWh), Statkraft (Norway, 49 TWh) and E.On Nordic (33 TWh).

However, the headline figures mask a number of trends. In Norway and Sweden, which commenced the liberalisation process earliest, the balance between production and consumption moved from a surplus of 17 TWh in 1990 to a deficit of 1 TWh in 2001 and back to a surplus of 9 TWh in 2007. Furthermore, 2000 and 2007 wet years in both Norway and Sweden, boosting output from hydropower stations. By contrast, 1996 was a very dry year in the region. In 1996, Norwegian production of hydropower was 167 TWh; in 2000 it was 234 TWh – a difference of 67 TWh[20]. Similarly in 2007 hydropower produced 23 TWh more than it had in 2006, when net imports across the Nordic market area had been 12 TWh.

By 2002, then, the system was very vulnerable to a dry year, as was demonstrated by the enormous increases in spot prices in the winter of 2002/3.

Norway

Before deregulation in 1992 the electricity supply industry in Norway had a three-level structure:

- Statkraft;
- regional wholesale companies;
- local distribution companies.

Statkraft was the State-owned generation and transmission company, responsible for about 30% of Norway's generating capacity (over 40% of output) and 70% of the transmission grid. There was also a power exchange market based on competitive bidding, which had been in operation since 1970.

A peculiarity of Norway's power systems is the dominance of hydropower, responsible for more than 99% of electricity generation. The system therefore has high investment costs but very low variable cost and therefore low cost variability. This does not necessarily lead to low price variability – limitations on reservoir capacity, variations in rainfall and significant changes in demand may cause price variations between years, between seasons and between day and night. In particular, in very dry years prices can be high in the winter (as happened in 1996 and in 2002/3) while in very wet years prices tend to be very low in the summer.

A number of arguments were advanced for liberalising Norway's electricity systems, many of them fundamentally the same as were being cited or were to be cited in other countries but some more specific to the Norwegian system with its very large number of locally-based participants and significant inter-regional variations in prices. They included[21]:

- avoidance of excessive investment – since the pricing policy of the entire electricity industry was based on cost recovery (as is often characteristic of centralised systems), utilities could mix the cost of expensive new development with that of cheap existing plants;

[20] http://www.eltra.dk/media/1030_13298.pdf, Nordel (2001), Annual Report 2000.
[21] http://www.elkraft.ntnu.no/~sie1065/kap%206.pdf, Aam S. and Wangensteen I. (1998), Restructuring/ deregulation of the electricity supply industry.

- improved selection of investment projects – it was believed that new capacity was not being developed in the most optimal way;

- creation of incentives for cost reduction – in a system where prices are based on cost recovery, there is no basic incentive for cost savings, since excessive costs are passed on to the customer;

- equity among consumers – the prices which customers were paying to different utilities were generally decided in local political forums quite independently of factors such as distance from hydropower generation facilities, and were often subject to extensive cross-subsidies, for example, between business and household sectors.

As elsewhere, the key innovation in the liberalised market was the separation of transmission from generation and the opening up of access to transmission and distribution systems to third parties. A new state-owned national grid company, Statnett, was created, while local distribution remained in municipal or county ownership. However, utilities, including Statkraft, were allowed to own both generating and supply businesses and Statkraft itself continues to play a dominant role in the production market, with a third of total generation plus stakes in BKK and Agder Energy)[22].

Sweden

Swedish liberalisation followed the Norwegian model in many respects. The grid was separated from trading activities and all electricity consumers were given the freedom to change their supplier. By the mid-2000s the seven largest power companies in Sweden accounted for more than 90 per cent of total generation. At the time of liberalisation there were nearly 200 companies distributing and supplying electricity, of which about half were municipally owned.

Finland

In Finland, prior to liberalisation, there were already several companies generating electricity. The State-owned IVO (Imatran Voima Oy) owned over 30% of total capacity (5,000 MW), other smaller utilities had capacity totaling almost 4,000 MW, distribution companies owned another 2,000 MW and industries a further 2,400 MW[23]. Unlike the other Scandinavian countries it had a wide range of power production technologies (including CHP) with no one dominating. There were about 10 regional networks and 100 local distribution companies mainly owned by municipalities and operating as local supply monopolies[24].

Finnish liberalisation came in response to EU energy policy and the development of Norwegian/Swedish cooperation. From 1995 reforms were instituted which:

[22] http://www.eia.doe.gov/emeu/cabs/norway.html, USDOE EIA (2009), Norway country analysis brief.
[23] Ministry of Trade and Industry (1997), Electricity market in Finland.
[24] http://www.sal.hut.fi/Teaching/Mat-2.142/elmarket/Saariselka/Grounds.pdf, Pineau P.-O. and Hämäläinen R.P. (1999), What are the grounds for electricity markets deregulation?

- created a new regulator, the Electricity Market Authority, to grant licenses for transmission operations and monitor transmission pricing;
- gave open access to all power lines;
- created a new company to operate the transmission network, Fingrid, owning the former transmission assets of IVO and PVO, and owned by IVO, PVO (25% each), institutional investors with no other interests in the electricity business (38%) and the Finnish government (12%);
- created a national power exchange, EL-EX, owned by Fingrid and being integrated into NordPool;
- forced unbundling of tariffs, so customers could see the proportions of their bills going to energy generation, transmission and supply/metering;
- opened the supply market to full competition[25].

However, the market remains concentrated, Fortum and PVO/IVO being together responsible for more than half of electricity generation.

Denmark

The Danish electricity market consists of two separate geographic markets, Denmark West (Jutland/Funen) and Denmark East (Zealand), placed between bigger power markets to the south (Germany) and to the north (Norway and Sweden). The two regions are not directly interconnected but are part of the wider Nordic grid. Denmark has two transmission system operators (TSOs): Eltra, which is responsible for the national grid in Jutland/Funen; and Elkraft, which is the national grid company in Zealand. About 100 local transmission/supply companies (owned by municipalities or directly by consumers) each have a small share in Eltra or Elkraft. Generation has to be legally separated from transmission/supply and each activity has to be carried out in separate companies. Generation companies are not allowed to own a significant share of transmission/supply companies. However, the local grid companies own the transmission system, the TSOs and the two large generation companies, so there is vertical integration by ownership if not by management.

DONG Energy dominates the Danish market, generating about half of the country's electricity. In 2006 it bought Elsam A/S in the west and Energi E2 A/S in the east, the near-monopoly generators in the two Danish markets. Interconnectors account for over 30% of total 'production' capacity in Denmark. The Danish generation and wholesale market has been gradually liberalised with the end-user market opened up from January 2003.

[25] http://www.sal.hut.fi/Teaching/Mat-2.142/elmarket/Sem_S98/FINLAND.PDF, Pineau P.-O. (1998), Overview of the Finnish electricity market.

NordPool

The Norwegian power exchange was established in 1993 and initially served the Norwegian electricity market only. In 1996 the exchange was extended to include Sweden, becoming the world's first multinational exchange for trade in electric power contracts. Subsequently Finland and Denmark joined the system. NordPool acted as the overall market operator and each constituent jurisdiction (Norway, Sweden, Finland and the two separate parts of Denmark) had its own independent system operator, in each case the owner of the grid. In 2002 NordPool was responsible for about 32% of the physical trade in electricity in the Nordic region[26].

In 2002 NordPool was reorganised into three different entities.

- NordPool, co-owned by the two State-owned national grid companies, Statnett SF in Norway (50%) and Svenska Kraftnät in Sweden (50%), organises financial trading.

- Nordic Electricity Clearing House (NECH), wholly owned by NordPool, is responsible for the clearing of both the financial and the physical market.

- NordPool Spot (NPS), co-owned (from July 2003) by Svenska Kraftnät, Statnett, Fingrid and NordPool with 20% each of the shares, with the remaining 20% of the shares distributed equally between the two Danish TSO companies Eltra and Elkraft, organises physical trading under the Norwegian Energy Act.

Since liberalisation there have been a number of high-profile mergers among generators. There has also been an increase in cross-ownership involving companies from outside the Nordic region.

Scandinavian liberalisation has been regarded as one of the most successful. A number of elements have contributed to this. The pan-Scandinavian market has allowed the participating countries to benefit from different fuel mixes in its constituent nations. In wet years hydropower produces cheap and flexible power, in dry years thermal and nuclear can be more reliable.

However, the generation market is quite concentrated, especially on a national level but also on a region-wide basis.

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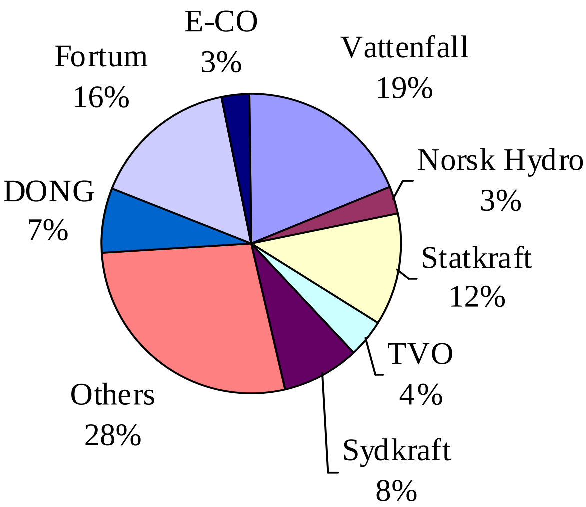
[26] http://www.nordpool.no/products/physical_market.html, NordPool (2003), The physical power market – Elbas and Elspot.

Figure 6: Electricity Production by Major Power Companies in the Nordic Region, 2005[27]



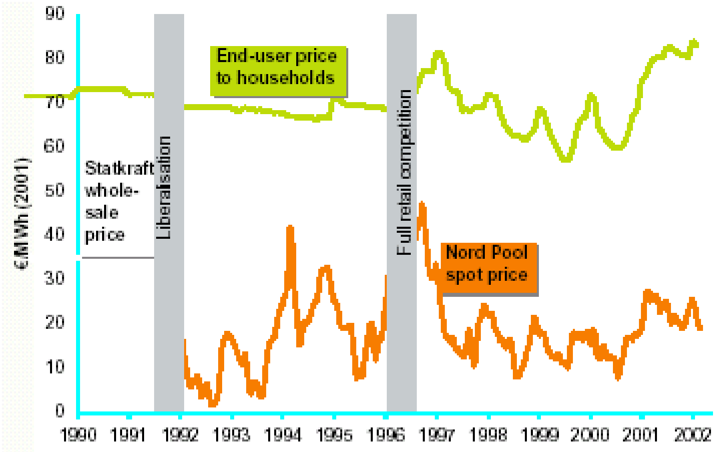
This is even more the case when cross-ownership is taken into account.

The regional market allows for individual participants to take advantage of surplus capacity elsewhere, mitigating the need to build new plants of their own. In 2007 Sweden and Finland were net importers while Norway and Denmark were net exporters within the Nordic region (though in 2006 Norway had been a net importer). Western Denmark (Jutland) is interconnected with the European grid.

In general, underlying power production costs have been low and stable since liberalisation. In most of the early years after liberalisation household prices in Norway were below those which pertained prior to liberalisation and spot prices were below Statkraft's wholesale price[28].

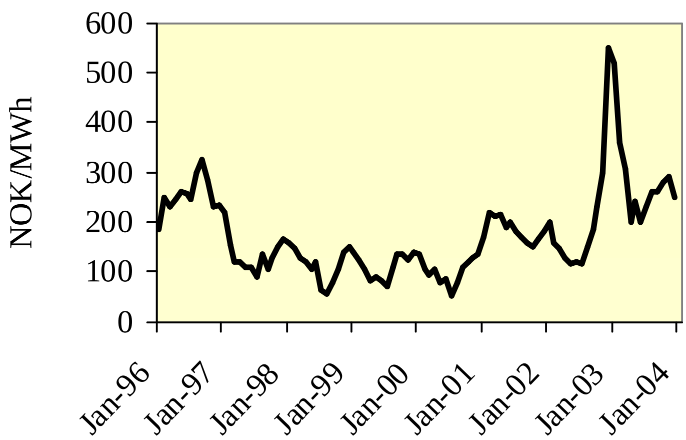
[27] http://www.samkeppni.is/samkeppni/upload/files/skyrslur/raedur_og_kynningar/eggum_johannssonaa.ppt, Johansen K. (2006), Competition policy in small economies.
[28] http://www.vpe.ch/pdf/elwo/Hoelsaeter_Statnett.pdf, Hoalsæter, O., Statnett (2003), Exchange of experience between Norway and Switzerland regarding the deregulation of the energy market.

Figure 7: End-user price to households, 1990-2002



However, during the dry summer of 1996 prices in NordPool rose significantly, as hydropower became less available.

Figure 8: Average Monthly Prices in NordPool[29]



This problem recurred in more serious fashion in 2002/3. A warm and dry summer (with the lowest rainfall since 1931) was followed by a dry autumn and a very cold winter. Water in hydropower reservoirs, already very low, froze over. NordPool prices tripled in a few days, while prices in Sweden rose by 260%. Finland and Denmark were rather less severely affected, being much less dependent on hydropower. Pool

[29] http://www.morganenergy.com/prices_np.php, Morgan Energy (2004), Prices – Scandinavia.

prices in February 2003 touched NK 870 (US$ 120) per MWh against a price of NK 200 (US$ 27) per MWh the previous year[30]. Some small distribution companies withdrew from the market, while some large manufacturers closed down production lines in order to sell the electricity bought under long-term contracts into NordPool.

The political response to price rises

Predictably, the situation led to calls for abandonment of the liberalised structure.

> 'What we've seen this winter is that the market doesn't function. The market works for companies but not for consumers who have to pay for electricity themselves.' (Hallgeir Langeland, MP, Socialist Left party[31].)

However (and crucially), the government stood firm, refusing to introduce panic reform to the marketplace. A variety of measures were taken to alleviate the situation. Output from thermal plants in the Nordic region increased by some 3.4 GW between October 2002 and February 2003 compared to the previous year, with several mothballed fossil-fired plants being brought into service. Marginal plants (generally oil-or gas-fired, usually used only to cover peak demand) were used for baseload and although emissions increased they were kept within permit levels. Plans were formulated to build new gas-fired plants should the crisis persist but these were abandoned as the problem abated.

The Nordic system also increased its imports. During the second week of 2003, almost 5% of the region's demand of 56,300 GW was imported. Furthermore, as the high prices fed through to industry and households (either directly or through the increased opportunity to resell electricity bought under long-term contracts), consumers took measures to reduce demand. This was especially true in Norway, where a higher proportion of power trading is done through the spot market rather than through long-term contracts.

It looks obvious that that the Norwegian electricity system would have been in trouble however it was structured because of the highly unusual reductions in the availability of hydropower. Be that as it may, the vital point was that Norwegian politicians did not intervene immediately to prevent the workings of the market, arguing that the successes of the previous twelve years of liberalisation should not be abandoned because of short-term difficulties. As a result price signals fed through to consumers leading to reductions in demand, while imports and generation from thermal generation plants increased, thereby preventing blackouts.

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[30] www.time.com/time/europe/magazine/article/0,13005,901030303-425836,00.html, Wallace C., Time (2003), 'Consumers in the Nordic region are furious over soaring electricity prices – and they blame deregulation'.

[31] Cited in www.time.com/time/europe/magazine/article/0,13005,901030303-425836,00.html, Wallace C., Time, (2003), 'Consumers in the Nordic region are furious over soaring electricity prices – and they blame deregulation'.

UNSUCCESSFUL LIBERALISATION – CALIFORNIA

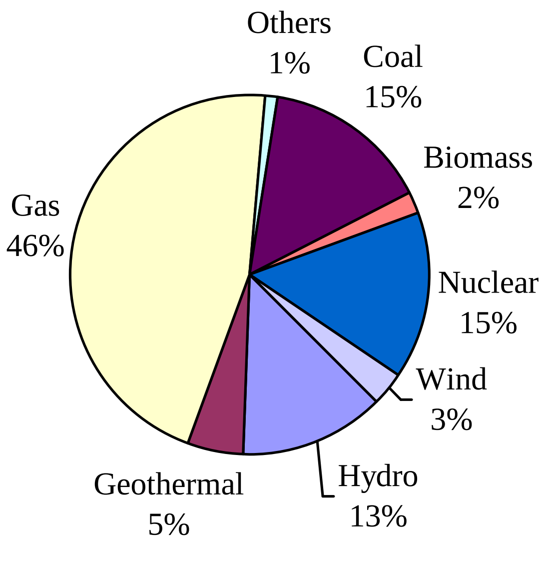
The most serious problems in recent years in the USA, with the possible exception of the blackout affecting the eastern seaboard in August 2003, beset California in 2000/2001.

Introduction and history

California is the most densely populated State in the USA, with about 27 million people. Its economy (the sixth largest in the world) is dominated by technology industries, for many of which uninterrupted electricity supplies are of great importance. Installed electricity capacity is of the order of 55,000 MW and in 1998, the year in which liberalisation of power supplies was introduced, the State used 276 TWh of electricity, a high proportion of which (17%) was imported[32]. (In addition, some plants owned by California utilities and not included in the imports figures were physically located outside of the State.)

In 2008 the mix of power sources, including imports (which accounted for 23% of the total) was as follows[33]:

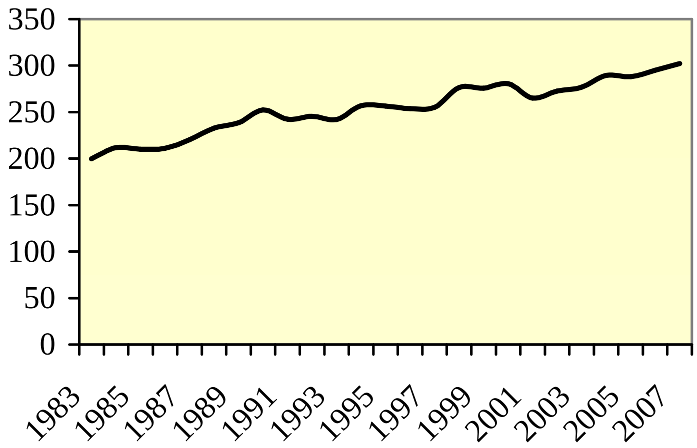
Figure 9: Sources of power in California, 2008



[32] http://www.ccsindia.org/Electricity/int_California_Elec_Crises.htm, Weinstein S. and Hall D. (2001), The California electricity crisis – overview and international lessons.
[33] http://energyalmanac.ca.gov/electricity/total_system_power.html, California Energy Almanac (2009), California electricity generation by resource type.

Power use had been increasing at a steady rate for some decades, rising by a total of over 40% in the period from 1982 to 2000.

Figure 10: Californian Electricity Generation (including imports) TWh



However, in common with the rest of the western region with which it is interconnected, commissioning of new capacity in California was slow in the 1990s. There were a number of contributory factors – significant overcapacity in 1990, a regulatory regime which made it difficult to make suitable profits from generating plant (as a California Energy Commission joke had it, ‘no plant gets approved unless the paperwork weights as much as the plant itself’), difficulties in obtaining licenses for environmental reasons and uncertainty caused by the announcement of impending liberalisation of the market. No applications for new plants of over 80 MW were filed between 1994 and 1998.

Before liberalisation, the Californian electricity system, like those in most US states, consisted mainly of vertically integrated, investor-owned utilities. About 80% of the State’s power was delivered by the three biggest utilities:

- Pacific Gas and Electric (PG&E) in the northern half of the State, including San Francisco;
- Southern California Edison (SEC) in the southern half of the State;
- San Diego Gas and Electric (SDG&E) serving the city of San Diego at the southern tip of the State.

The utilities owned power plants plus transmission and distribution facilities and sold power to individual retail customers within their franchise areas (in which they had a monopoly) at prices set by the California Public Utilities Commission (CPUC).

The rest of the State’s power was provided by several municipally owned utilities, the largest of which (indeed the largest in the USA) was the Los Angeles Department of Water and Power (DWP). Although these were interconnected with the wider California grid systems they were under local democratic control and not subject to price regulation by CPUC.

Utilities would from time to time buy power from neighbouring utilities on a bilateral basis, to meet unusual situations (e.g. unusually high peak demand or an unexpected plant outage) or on a longer-term basis to take advantage of excess capacity in another area.

The main exception to the vertically integrated structure involved the Qualifying Facilities, built under the provision of PURPA[34]. By 1985 there was over 15,000 MW of QF capacity under contract in California (not all of which would be built) and CPUC suspended the process. By 1992 9,500 MW of QF capacity were generating over 25% of the electricity needs of the three utilities[35].

The existence of QFs on the system did not lead to any major problems over integrating their output into demand patterns, so demonstrating both that vertical integration was not essential to system stability and that independent investment could result in significant new capacity being built relatively quickly. This being said, the QFs could be regarded as ‘virtual capacity’ belonging to the utilities, since they were generating under exclusive long-term contracts to those utilities: experience of QFs did not offer any evidence for (or against) the concept that establishing a spot market could either encourage new investment in generation capacity or provide stable real-time supplies.

As California entered the 1990s, then, it had a capacity margin of 40% and relatively high power prices – household power prices charged by the private utilities were of the order of 9 to 10.5¢ per kWh, some 30-50% above both the national average and the competitive rate for new supplies[36]. Deregulation in other industries such as trucking and telecommunications seemed to be having positive consequences. In September 1992 CPUC launched a review of the Californian power market[37].

The structure of the new market

What emerged was the following.

The utilities were strongly encouraged to divest themselves of their fossil-fuel generating plant, in return for a deal which would allow them to recoup their ‘stranded costs’ by April 2002[38] from a combination of electricity tariffs and government

[34] In 1978 the Public Utility Regulatory Policy Act (PURPA) was introduced which allowed for private companies to build and operate generating plant (mainly using renewables) and sell the output under long-term contracts to the local utilities. PURPA was very effective in attracting independent private investment into electricity generation (not least because the contract terms were based on the very high oil prices of the late 1970s) and demonstrated that full vertical integration was not necessary for either financial reasons or reasons of system reliability.

[35] http://www.ucei.berkeley.edu/PDF/csemwp103.pdf, Blumstein C., Friedman L. and Green R., CSEM (2003), The history of electricity restructuring in California.

[36] http://tonto.eia.doe.gov/FTPROOT/electricity/0348961.pdf, USDOE EIA (1997), Electric power annual 1996.

[37] http://www.ucei.berkeley.edu/Restructuring_Archive/Yellow_book.pdf, Dasovich J., Meyer W. and Coe V., California Public Utilities Commission (1993), California’s electric services industry: perspectives on the past, strategies for the future.

[38] ‘Stranded costs’ were the costs of generation plant which had not yet been paid off (it having been assumed that the utilities would have a captive market at high prices for the lifetime of these plants) plus the excess costs of contracts held with QFs. A long debate took place as to whether companies should receive any compensation for their stranded plants or whether the risk of market regulations changing radically was an ordinary business risk, the consequences of which should be born by investors.

guarantees for new tax-free 'rate reduction bonds'. These costs were estimated at between $21 billion and $25 billion at the time the new market was established[39].

Two new not-for-profit bodies were established.

- The Power Exchange (PX), which operated a day-ahead hourly spot market for auctions between generators and purchasers – in effect trading 'raw' electricity by the MWh. Like the UK electricity Pool, on which it was largely modelled, the system price would be equivalent to the bid price of the marginal offer, which was usually gas-fired.

- The Independent System Operator (CAISO) to manage system aspects, e.g. arranging for transmission access for successful PX bids, maintaining a reserve of plant for times when insufficient plant was contracted through the PX and making sure that supply and demand exactly balanced in real-time, a crucial function if voltage and frequency of supplies is to be maintained.

The utilities were mandated to buy their electricity only from the PX – they were not allowed to sign bilateral 'vesting contracts' with their own generating output or independent producers – and had to sell their own real and virtual (QF) output through the PX. CAISO's responsibilities included making sure that distribution wires did not become overloaded (e.g. by making some northern California plants shut down and commissioning power from more expensive southern ones on days where there was excess demand in the south of the country).

Consumers were eligible to switch their demand to alternative retail providers but for a variety of reasons (including the requirement that they should not be able to avoid making their contribution to paying off the utilities' stranded costs) very few did so. By early 2000 only 1% of residential consumers and 20% of industrial ones had switched supplier. Enron abandoned the household supply market within just three weeks[40].

In order to ensure a 'quick win' (and to gain wider support for the whole scheme) the retail price charged by the utilities was to reduce by 10% in the first four years of the liberalised system, which after some delay started in April 1998. It was assumed that the gap between the (capped) price charged to customers and the wholesale price the utilities would be paying through the PX (plus distribution charges) would be sufficient to allow for the stranded costs to be paid off within that four year period.

The outcomes

The utilities rapidly divested themselves of their fossil-fuelled (or 'thermal') generating capacity, in fact at a faster rate than they were mandated to do. SCE sold most of its thermal units in the two months following the opening of the market in April 1998, PG&E sold most of its in the first year and SDG&E divested its thermal units in mid-1999. Five companies – AES, Duke, Dynergy, Reliant and Southern/Mirant – each bought about one fifth of the divested capacity. The fact that these plants were sold for

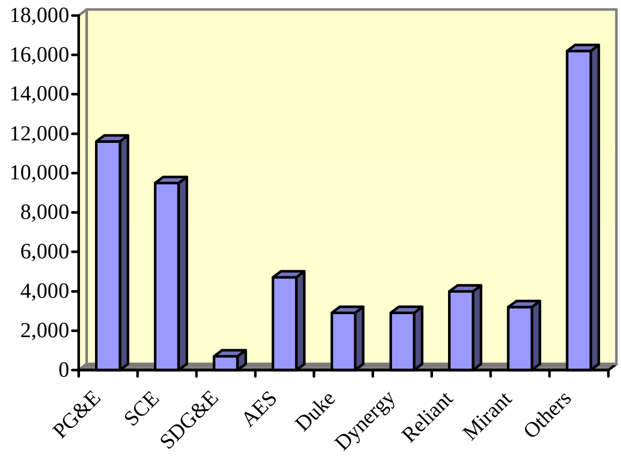
[39] http://www.cato.org/pubs/regulation/reg20n2i.html, Michaels M., Regulation (1997), 'Stranded in Sacramento: California tries legislating electricity competition'.
[40] Flaim, T., Electricity Journal (March 2000), 'The big retail 'bust': what will it take to get to true competition?'

high prices – a total of some $3.1 billion against book value of $1.8 billion[41] – may with the benefit of hindsight be taken as evidence that the purchasers expected power prices to rise significantly.

The utilities retained their nuclear plants (running at baseload), some hydro and responsibility for long-term contacts with QFs. At the end of 1999 Californian generating capacity was distributed as follows:

[41] http://archive.salon.com/news/feature/2001/01/30/deregulation_mess/index.html, York, A., Deregulation, (January 30, 2001), 'The deregulation debacle'.

Figure 11: Generating Capacity in California at the End of 1999 (MW)[42]



('Others' were companies owning less than 1.000 MW of capacity in California)

In its initial months the PX worked smoothly, with an average wholesale price of $26.2 per MWh in 1998/9 and $31.2 per MWh in 1999/2000. At these wholesale prices (well below the retail price cap) the utilities could make a considerable contribution to paying off their stranded costs – some $17 billion of debt was retired in those two years[43] – and indeed SDG&E succeeded in paying off all these costs by the end of 1999. There were some shortages in CAISO's reserve market and prices there reached $9,999 per MWh in July 1998 before falling back after a $500 per MWh cap was imposed (raised to $750 per MWh in October 1999).

In the summer of 1999 the PX opened a short-term (one year ahead or less) futures market. SCE took up longer-term contracts to cover 20% of its demand – the maximum that CPUC was prepared to underwrite – while PG&E and SDG&E stayed with the spot market for almost all of their requirements. Experience with the QFs (with whom the utilities were tied into long-term contracts at prices significantly above the spot price) acted as a deterrent to the signing of long-term bilateral contracts and the whole system remained very heavily dependent on the PX spot market.

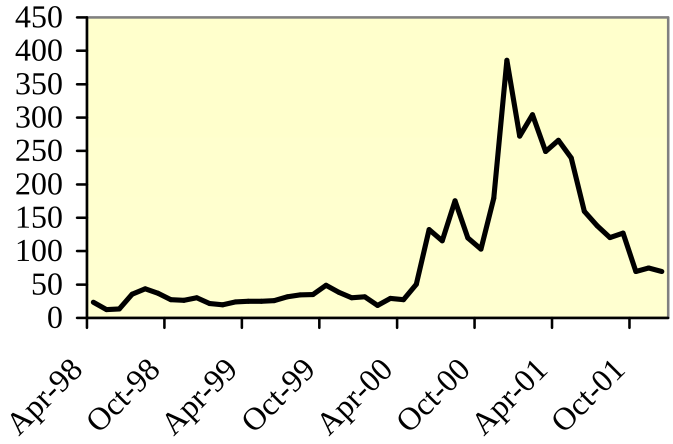
Market collapse

Late in the spring of 2000 the market began to fail. In June wholesale prices averaged $132 per MWh. CAISO reduced the price cap in the day-ahead market to $500 per MWh on July 1 2000 and to $250 per MWh in August[44]. Prices stabilised a little, only to

[42] http://www.ucei.berkeley.edu/PDF/csemwp103.pdf, Blumstein C., Friedman L. and Green R., CSEM (2003), The history of electricity restructuring in California.
[43] Smith R. and Emshwiller, Wall Street Journal (January 4, 2001), 'California's PG&E gropes for a way out of electricity squeeze'.
[44] http://econ-www.mit.edu/faculty/download_pdf.php?id=540, Joskow P. and Kahn E. (2002), A quantitative analysis of pricing behaviour in California's wholesale market during summer 2000.

spike dramatically in December, when prices averaged $386 per MWh as significant amounts of capacity were moved into CAISO's real-time market to avoid price caps.

Figure 12: Average Monthly Wholesale Power Price in California ($/MWh)[45]



By the end of January the collapse was complete. Blackouts occurred on eight days, the PX suspended operations and the CAISO, SCE and PG&E were all insolvent.

Table 3: California Blackouts 2001/01[46]

Date	Day	Peak demand (GW)	Power curtailed (MW)	Number of hours Curtailed
14/6/00	Wednesday	44.2	100	
17/1/01	Wednesday	29.7	500	3
18/1/01	Thursday	29.5	1000	3
21/1/01	Sunday	27.7	100	1
19/3/01	Monday	29.5	1000	6
20/3/01	Tuesday	29.7	500	6
7/5/01	Monday	33.4	300	2
8/5/01	Tuesday	34.5	400	2

Reasons for the collapse

The precise reasons for the failure of the Californian market are still being debated in academic and legal circles.

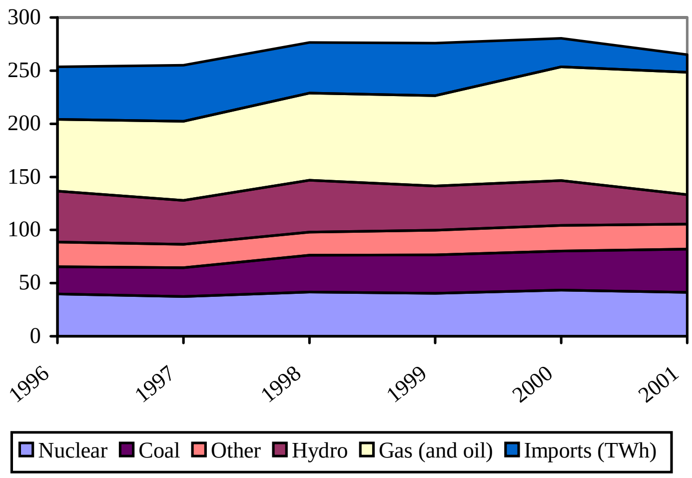
[45] http://www.econ.jhu.edu/People/Harrington/Joskow01.pdf, Joskow, P., Oxford Review of Economic Policy (Autumn 2001), 'California's electricity crisis': http://www.cpuc.ca.gov/static/industry/electric/electric+markets/histyroical+information/average+energy+costs+2000+thro+2001.xls, CPUC (2002), Average energy costs 2000 thro' 2001.
[46] http://www.caiso.com/docs/09003a6080/08/8a/09003a6080088aa7.pdf, CAISO (2004), System status log.

The position of the utilities was relatively straightforward. Being almost completely exposed to the spot market, they were facing the impossible situation of paying very high wholesale prices for power from the PX – the average price stayed above $100 per MWh from June 2000 to September 2001 – but being capped in the price they could charge their industrial customers at below $70 per MWh (7¢ per kWh). Inevitably they became insolvent, with huge debts. With the benefit of hindsight, the utilities would have benefited considerably from being less exposed to the spot market by taking more forward positions. PG&E filed for bankruptcy in April 2001 – it would take over two years for a compromise between CPUC and PG&E which would allow the utility to keep trading under State review.

The situation with respect to generation is more complex. The first point to note is that only one of the eight blackouts occurred when demand exceeded 35,000 MW. The one in which demand did exceed this occurred because of transmission restraints rather than a shortage of available power capacity. Peak demand in 2000 (43,500 MW) was actually lower than in 1999 (45,600 MW)[47].

The low rainfall in the winters of 1999/2000 and 2000/2001 significantly curtailed the availability of hydropower in the region, affecting both California's own capacity (the hourly average hydropower on the system fell from 4.4 GW in 1999 to 2.6 GW in 2000) and the ability of other States in the western region to export[48].

Figure 13: Californian Energy Production (TWh) 1996-2001[49]



The shortage of investment in new capacity in the western region generally in the 1990s certainly did nothing to ease this. Nonetheless, it is difficult to ascribe the problems of 2000/2001 to an absolute shortage of electricity capacity. The problem was that existing capacity was not available.

[47] http://enduse.lbl.gov/Info/LBNL-47992.pdf, Brown R. and Koomey J., Energy Policy (2002), 'Electricity usage in California: part trends and present usage patterns'.
[48] Krapels E., Public Utilities Fortnightly (February 15, 2001), 'Was gas to blame?'
[49] http://uclaforecast.com/infrastructure/datasets/EGRT.XLS, UCLA Anderson (2002), California electrical energy generation 1983 to 2002.

A number of other factors were involved. There was widespread abuse of market power and it is certainly striking that one of the days on which power cuts were imposed was a Sunday while on only one of the six days was demand especially high. Documents released after the collapse of Enron in 2002 show that the company followed a policy of overstating its customers' requirements, causing the independent system operator CAISO to pay Enron (and other traders) a premium for providing an excess of power which it then had to buy back at a cheaper rate. Enron also flooded the distribution system with power in order to trigger high 'congestion charge' payments (up to $750 per MWh) in the infamous 'Death Star' strategy[50]. In June 2003 the FERC ordered sixty power traders and municipal utilities to explain why they should not have to repay unfair profits reaped from allegedly manipulating the market during the crisis[51] and in 2005 Mirant paid $458 million (without admitting liability) to settle claims that it received unfairly high price for sales during the crisis[52].

One of the days on which rolling power cuts were imposed was a Sunday, during which demand was about 27.7 GW, just 60% of the summer system peak. During June 2000 there was a 21% surplus in available plant capacity through the western region at a time when CAISO was declaring an emergency because California's margins had fallen below 3%[53].

The most obvious tactic in these circumstances would be for operators to withdraw a larger than expected (or needed) degree of capacity for maintenance, so forcing up the system marginal price. It is reported that at one point CAISO was sending inspectors to off-line plants to check that the outages were really necessary, although it was true that much of California's plant was over 35 years old with significant maintenance requirements. Whatever the reason, at times during November and December 2000 up to 45% of all merchant generators were unavailable because of 'maintenance problems'[54]; on January 17 2001, one of the blackout days, it was reported that 11,000 MW of in-State capacity was off-line.

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[50] http://www.wsws.org/articles/2002/may2002/enro-m10_prn.shtml, Isaacs J. (2002), Enron defrauded California out of billions during energy crisis.

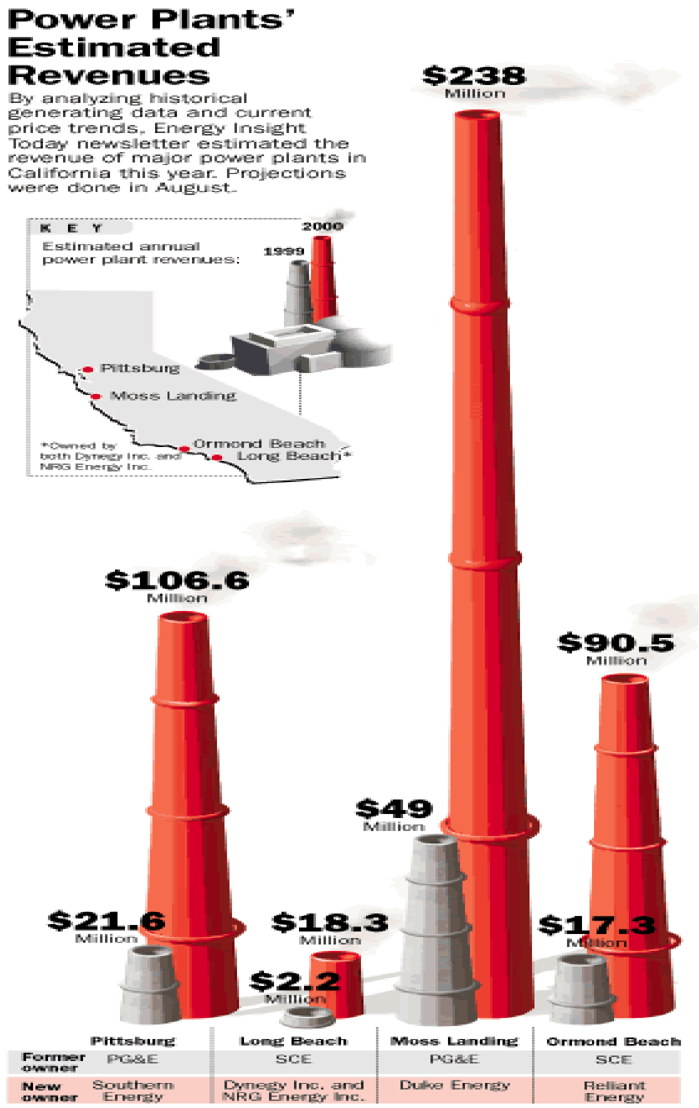
[51] http://www.oppc.net/press/2003-06-25_ferc_orders.html, Reuters (June 25, 2003), FECR orders 60 firms to justify Calif. Profits.

[52] http://www.corporate-ir.net/ireye/ir_site.zhtml?ticker=MIR&script=415&layout=0&item_id=662236, Mirant News Release (January 14, 2005), Mirant reaches agreement with California utilities and public agencies to settle claims related to State's 2000 and 2001 energy crisis.

[53] McCullough R., quoted in http://www.ccsindia.org/Electricity/int_California_Elec_Crises.htm, Weinstein S. and Hall D. (2001), The California electricity crisis – overview and international lessons.

[54] North Counties Times, San Diego (December 15, 2000).

Figure 14: Californian Power Generators' Revenues, 2000/2001[55]



Where the generator owned assets in other States as well as California it even made sense to shut down in-State capacity which would be subject to the CAISO price cap and instead import power into California from its out-of-State plants (and so avoid the cap).

It is not necessary to assume illegal activity (à la Enron) or collaboration – generators may simply take notice of signals from their rivals' behaviour and so act as an informal cartel.

[55] http://www.ccsindia.org/Electricity/int_California_Elec_Crises.htm, Weinstein S. and Hall D. (2001), The California electricity crisis – overview and international lessons.

Final stages

The final nail in the market's coffin came when the FERC intervened in the wholesale market in late 2000[56]. The FERC replaced the previous firm caps on generating prices with a 'soft cap' of $150 per MWh (to apply in both the PX and CAISO) which proved easy to bypass or simply to ignore. What the FECR intervention did, though, was to reduce the volume of power going through the PX to practically zero, as most of the non-utility generators had already shifted their sales into the real-time market to avoid price capping. (CAISO was taking a 'keep the lights on at all costs' approach which was leading it to pay extremely high tariffs in the reserve market. Of course anyone bidding into this market faced the possibility that they might not be called, but if they were they could earn several times the $250 per MWh cap in the PX, making the gamble an attractive one. CAISO was therefore operating in violation of the FECR 'soft cap'.) PX suspended operations in January 2001 and declared itself bankrupt in March 2001.

Meanwhile, PG&E and SCE defaulted on payments due to the PX, causing the PX in turn to default on payments to CAISO for balancing generation. CAISO became insolvent as well: the whole market had collapsed. Emergency legislation allowed the California Department of Water Resources (CDWR) to procure electricity, both through spot purchases and long-term contracts whose terms were kept secret. Supply remained tight owing to continuing low rainfall and power cuts continued into May.

Los Angeles

As an aside, it should be noted that the municipally owned DWP in Los Angeles, with 3.8 million customers, which remained vertically integrated while SCE, PG&E and SDG&E were divesting generating assets, benefited significantly from the Statewide crisis. It was reported that, foreseeing shortages elsewhere, the city brought some generating plant out of mothballs to take advantage of soaring PX prices outside the city, while keeping rates to their own citizens relatively low. Similar claims were made on behalf of other municipal utilities in Pasadena, Sacramento and a number of other cities. While it is true that, prior to 2000, the prices in Los Angeles were rather higher than those which were being paid through the PX, in order to compensate for unused reserve capacity[57], it is difficult to avoid the conclusion that, in the particular circumstances that faced California in the five years following the introduction of the market reforms in 1998, Los Angeles did well to keep out of it. This may serve as evidence for the proposal that command-and-control is preferable to a compromise liberalisation which seeks to mix market discipline with government intervention for (supposed) social reasons.

The aftermath

In June 2001 prices fell sharply and there has been no recurrence of the power cuts. Although there were times in which plant margin was a matter for concern – for example in July 2003 following an unexpected withdrawal of 2,250 MW of capacity –

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[56] http://www.ucei.berkeley.edu/PDF/csemwp103.pdf, Blumstein C., Friedman L. and Green R., CSEM (2003), The history of electricity restructuring in California.
[57] http://www.cato.org/pubs/pas/pa406.pdf, Taylor J. and VanDoren P. (2001), California's electricity crisis – what's going on, who's to blame and what to do.

the situation in 2003 was significantly easier than it had been on days of power cuts two years earlier.

A number of factors seem to have contributed to the recovery. In the summer of 2001 Californians reduced their demand for electricity while in May and June California gas prices fell from around $12 per MMBtu to $5 per MMBtu, reaching the historical average price of $2-$3 per MMBtu by September. Weaker demand, higher levels of storage and reformed pipeline allocation rules have been cited as possible reasons. This reduced the operating costs for gas-fired generators, including the marginal plants which would have set the system price in the PX[58].

In April 2001 the FERC capped generator prices (based on fuel costs) in the entire western region, preventing 'megawatt laundering' (the practice of in-State generators exporting output to neighbouring States and re-importing it to avoid the cap). Generators were mandated to offer all available capacity and the market price was set at the highest accepted bid (similar to the arrangements under the PX). Furthermore, the nuclear unit San Onofre-3 came back on line (having been down since January) and some 1,400 MW of new thermal capacity was brought into operation.

In 2001/2 many of the tenets of the liberalisation of California's power markets were abandoned. The State tied itself into long-term power contracts (at high prices by historical standards) and prevented direct-access contracts between consumers and generators at lower prices. Concern transferred to an expected slump in forward prices and worries about oversupply[59] - further powerful evidence that what had gone wrong was more a matter of market design than fundamental shortages of capacity. The FERC price cap on generators was raised from $55 per MWh to $92 per MWh in July 2002[60]. In due course the utilities moved back into plant ownership – for example, in July 2003 SCE bought options to complete the 1,050 MW Mountainview CCGT that had been started by AES, intending to buy the electricity on a 30-year contract[61]. FERC gave permission for SCE to build the plant without competitive bidding, a step regarded as retrograde by some commentators who expressed fears of creating new stranded costs[62].

The election of Governor Schwarzenegger in October 2003 appeared to signal a return to a more pro-competition policy in California. The Schwarzenegger website[63] contained a detailed position statement on energy, one of only seven categories listed as part of his agenda. The statement focused on electricity markets and emphasised California's high electricity prices, increasing demand, need for investment in infrastructure, flaws in the original deregulation and the need for California to become competitive with surrounding States. Schwarzenegger stated that 'as Governor, I will . . . make markets work', and *inter alia* pledged to:

- abolish the California Power Authority;

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[58] Wilson J., Journal of Industry, Competition and Trade (June 2002), 'High Natural Gas Prices in California, 2000-2001: Causes and Lessons'.
[59] http://wsws.org/articles/2002/jan2002/cali-j04_prn.shtml, Cappannari A., World Socialist Web Site (4 Jan 2002), 'California's energy debacle continues'.
[60] http://www.bizjournals.com/sanjose/stories/2002/07/07/daily61.html, Silicon Valley/San José Business Journal (July 12, 2002), 'FERC raises cap on power prices'.
[61] http://pqasb.pqarchiver.com/latimes/370911591.html?did=370911591&FMT=ABS&FMTS=FT&date=Jul+18,+2003&author=Nancy+Rivera+Brooks&desc=New+Power+Plant+for+Edison, Brooks N., Los Angeles Times (July 18, 2003), 'New power plant for Edison'.
[62] E.g. Jan Smutny-Jones, quoted in http://www.mtburr.com/Images/PUR/Back-to-the-Ratebase.pdf, Burr T., Public Utilities Fortnightly (March 2004), 'Back to the ratebase'.
[63] http://www.joinarnold.com/en/agenda, Schwarzenegger A. (2003), Join Arnold.

- merge CAISO and PX;
- pass through costs of higher power prices in real-time to facilitate rational market responses, e.g. load-shedding, at times of tight capacity margins;
- enact capacity reserves requirements;
- coordinate reserve policy with the rest of the Western Electricity Coordinating Council;
- diversify away from natural gas for electricity generation;
- promote renewables;
- limit the powers of CPUC;
- explore options for renegotiating or otherwise reducing the cost of the $43 billion of overpriced electricity power purchase agreements signed by the Davis government in the aftermath of the crisis.

DISCUSSION AND CONCLUSIONS

Predictably, a crisis like California will be blamed by those on the Left on too much liberalisation:

> 'We must face reality. California's deregulation scheme is a colossal and dangerous failure. It has not lowered consumer prices. And it has not increased supply. In fact, it has resulted in skyrocketing prices, price gouging and an unreliable supply of electricity. In short, an energy nightmare. We have lost control over our own power. We have surrendered the decisions about where electricity is sold, and for how much, to private companies with only one objective – maximising unheard-of profits.'[64]

And by those on the Right on too little:

> 'Deregulation never really took place in California. Instead, political forces imposed a contrived market structure that made failure almost predictable. California's disaster was of its own making and largely avoidable.'[65]

> 'The California electricity crisis is not really a story about environmentalists gone bad, deregulatory details ignored or capitalists running amok. It's a story about what happens when price controls are imposed on scarce goods.'[66]

Oddly, both may be right. If policymakers are confused about the extent to which they regard electricity as a commodity and as a social service, they may well try to introduce a hybrid system like that which pertained in California in which a broadly competitive market framework (in which companies will behave like profit-making entities rather than agent of social good – why, one might ask, introduce commercial companies into the electricity supply business if policymakers do not want them to behave like commercial companies?) is overlaid with extraordinary levels of regulation, which changes on an unpredictable basis in response to the whims of politicians and regulators trying to protect some concept of 'public good'.

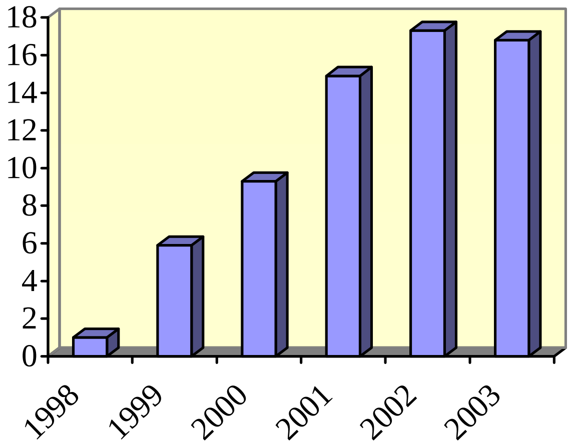
A competitive market with minimum regulatory interference would presumably give investors confidence to invest in a timely fashion. Heavily capital-intensive industries such as petrochemicals tend to go through an investment cycle, lasting perhaps seven years. To start with capacity gets tight, prices rise and companies dash to make new investment. For a couple of years prices and profits are high, this serving as the incentive to get involved in the first place. Then, as capacity grows (and often as demand moderates owing to the high prices) prices start to fall, resulting in consolidation and even bankruptcies. Eventually capacity contracts to such an extent that prices start to rise and the cycle begins again. In effect the manufacturers make major profits for two years, consumers enjoy low(ish) prices for five years and the overall efficiency of the cycle is better than it would be in the hands of monopolies

[64] http://video.dot.ca.gov/state/transcript.html, Davis G. (January 8, 2001), State of the State Address.
[65] http://www.ncpa.org/pub/ba/ba348/, Michaels R. (2001), California's electrical mess: the deregulation that wasn't.
[66] http://www.cato.org/pubs/pas/pa406.pdf, Taylor J. and VanDoren P. (2001), California's electricity crisis – what's going on, who's to blame and what to do.

protected from commercial pressures of any description. In the case of electricity there would be some concerns about whether investment would happen early enough to prevent the first power cuts, but there are market mechanisms in operation in PJM (Pennsylvania-New Jersey-Maryland) and New England, for example, which can encourage this.

However, liberalisation in many developed markets is now grinding to a halt. For example, the US Centre for the Advancement of Energy Markets (CAEM) publishes an annual 'RED (Retail Energy Deregulation) Index' of the degree of liberalisation in various power markets. The average deregulation score across the USA, having risen since 1998 when the Index was introduced, stalled in 2003 at 17. (For comparison, the England/Wales score for 2003 was 83 and New Zealand's 75.)

Figure 15: US National Simple Average Score, Red Index



In its 2003 report[67], CAEM found that:

> 'Market instabilities in 2001 and 2002 have resulted in some US States delaying or cancelling their plans to reform their retail markets. Jurisdictions that have just started to reform are moving cautiously to avoid 'another California'. The structure and pricing of default service has taken centre stage in many regulatory proceedings. Regulatory inaction has increased uncertainty for market stakeholders.'

The change in attitude over a very short period of time is striking.

> 'Liberalisation of energy markets has brought great benefits to a lot of people. For consumers, it has brought greater choice of products, lower prices and a general improvement in the quality of service. For companies it has meant the freedom to develop

[67] http://www.caem.org/website/pdf/RED2003.pdf, CAEM (2003), Electricity retail energy deregulation index 2003. Interestingly, CAEM abandoned its surveys of liberalisation in 2004, coincident with growing calls for a reversal of liberalisation measures in several US states and elsewhere.

> new ideas, to build their business and to reap the rewards of success. The benefits of competitive energy markets are now widely accepted in the rest of the EU and there is widespread support for the creation of a policy framework to underpin the establishment of a functioning internal energy market.'
>
> (UK Energy Minister Peter Hain, March 2001[68])

> 'Power is now a dirtier word in banking than telecoms. In the USA, UK and Latin America there are no investors, no banks and deregulation is losing credibility.'
>
> (Tony Marsh, EBRD Cofinanciers' meeting, March 2003[69])

> 'Since the [Electric Energy Market Competition Interagency] Task Force initiated its investigation in October 2005, the state of electric industry restructuring continues to change – and change for the worse. There is growing sentiment among consumer groups and the States that restructuring is failing to deliver benefits to end-use consumers, and is beginning to impose economic hardship on the US economy – especially to the country's manufacturing sector[70].'
>
> (Electricity Consumers Resource Council (ELCON), April 2006)

The current status of liberalisation in many markets appears questionable if not untenable, for a number of reasons.

- In almost all liberalised markets investment in new generating capacity appears inadequate to maintain a suitable capacity margin, thereby threatening security of electricity supplies.
- There are strong suspicions of abuse of market power as the degree of integration (both vertical and horizontal) has grown, resulting in very high price spikes and, in the case of California, extreme distortion of what might be regarded as rational behaviour.
- The growth of cross-border electricity trading without an accompanying growth of cross-border system operators has been accompanied by major power outages in Europe, Australia and North America, especially in the first half of the decade.

[68] http://www.dti.gov.uk/ministers/archived/hain070301.html, Hain P. (March 7, 2001), Speech to Electricity Association dinner.
[69] http://www.ebrd.com/oppor/syndi/meeting/pres/power.pdf, Marsh A., EBRD cofinanciers' meeting (March 11, 2003), Power and energy.
[70] http://www.elcon.org/Documents/FERCFilings/ELCONSupplementalComments.pdf, ELCON (2006), Supplemental comments on wholesale and retail electricity competition.

- There is growing scepticism in some quarters as to whether markets, even with heavy interventionist measures, can deliver the environmental improvements required.

The underlying tension

Underlying many of these problems is ambivalence on the part of governments. In 1982, Energy Secretary Nigel Lawson propounded a major shift in government's attitude towards energy.

'I do not see the government's task as being to try to plan the future shape of energy production and consumption. It is not even primarily to try to balance UK demand and supply for energy. Our task is rather to set a framework which will ensure that the market operates in the energy sector with a minimum of distortion and energy is produced and consumed efficiently[71].'

It is a matter of legitimate debate as what the 'framework' should include. Market imperfections must be addressed – one might argue that it is inconsistent, for example, that nuclear energy should internalise the cost of all of its waste management while generators using fossil fuel can still largely emit greenhouse gases and acid rain gases without significant penalties, sulphur and carbon allowance trading notwithstanding. (It seems unlikely that the cost of credits through the European trading scheme, for example, at around €11 a tonne, will make much difference to investment decisions in new generation plants.) Similarly, experience of the growth of oligopolistic behavior suggests that government should play an active role in preventing the creation of cartels and in forcing companies to compete. (The tendency to create monopolies is probably even greater in electricity than in many other industries – competition is expensive, since it requires spare capacity which is both costly to maintain and tends to suppress power prices.) Some aspects of the process, notably the maintenance and operation of the transmission and distribution wires, will remain natural monopolies, requiring clear regulation to ensure open access to third parties and to prevent overcharging, while allowing sufficient return on capital for investment in upgrades and extensions as required. Furthermore, the nature of electricity – that it cannot be stored in significant quantities – is such that a system of payments for companies prepared to keep capacity available in order to keep the lights on during unexpected events may be beneficial. Such 'capacity payments' are a feature of many of the more successful liberalised power markets.

A market designed along these lines will certainly 'work' in many ways, especially if rules are set for reasonable periods of years instead of being changed on a regular basis. One would expect the underlying costs of electricity generation and supply to be lower than the case in the monopolisitic command-and-control market, owing for example to the disciplines of the marketplace and the associated stimulus to innovation. As capacity margins tighten prices rise and, as long as there is no heavy-handed intervention on the part of government or regulators, those high prices will in due course act as signals for new investment, which will in turn reduce the high prices and the new cycle will begin. Whether secure power supplies could be ensured at all times is unclear, though one should note that absolute supply security cannot be guaranteed in any event and too much security can be enormously expensive. The

[71] Lawson N. (1982), reproduced in Helm D., Kay J. and Thompson D. (1989), The Market for Energy, OUP.

practical debate is one of degree, not absolutes. However, the philosophical debate is perhaps clearer.

Well-meaning troublemaking

The problem is that many governments have seen their role as extending well beyond such 'mechanical' intervention in the marketplace, designed simply to ensure fair competition. Governments also intervene to 'guide' the market to fulfill other social and economic goals (in effect regarding energy not as a commodity but as a social service). Such intervention serves to damage confidence on the part of potential investors and therefore to delay investment and to increase its cost, often to the direct detriment of the very people government intends to help.

Because of the long periods of relatively low prices that are typical of electricity markets (e.g. overnight, during mild weather), if new investment is to be attractive the difference between the market price and operating costs at times of narrow operating margins must be very large, considerably larger than in commodity markets in which the product can be stockpiled at times of low price. It is at least likely that, faced with a prolonged period of high wholesale power prices especially if these fed through to residential electricity bills, governments or regulators will intervene to cap these prices rises in the face of populist cries of 'extortion'. Even if the prices being charged were the minimum required to encourage new investment, some commentators would undoubtedly point to the gap between these prices and operating costs and interpret this as profiteering on the part of the generators. There will almost certainly be suspicion (possibly but not necessarily unfounded) that the generators with the greatest market power are exploiting the underlying power shortage in order to magnify increases in prices.

In its 2003 Energy White Paper, the UK Government stated[72]:

> 'We will not intervene in the market except in extreme circumstances, such as to avert, as a last resort, a potentially serious risk to safety.'

To his credit, Energy Minister Malcolm Wickes resisted calls to intervene in response to rises in gas prices in 2005/6. However, experience of other liberalised power markets suggests that governments very often do intervene in electricity markets to prevent significant power price rises or for other reasons. The 'privatisation' of, say, British Telecom in the UK involved selling both the hardware of phones and wires but also the responsibility for providing telecommunications. The 'privatisation' of the railways, by contrast, left a considerable part of the responsible for guaranteeing services in government hands and indeed resulted effectively in re-nationalisation. In practice the privatisation of electricity may resemble the latter more than the former – if the lights do go out or power prices increase to unacceptable levels it is very unlikely that the government of the day will avoid censure.

One common instrument of intervention is the price cap. Examples of price caps include:

- US$ 70 per MWh for Californian consumers and (at various times) of $55, $92, $150, $250, $500 and $750 per MWh for generators;

[72] http://www.dti.gov.uk/energy/whitepaper/ourenergyfuture.pdf, DTI (2003), Our Energy Future – creating a low carbon economy.

- FERC price cap for the whole of the US Western Interconnection following the California crisis;
- US$ 1,000 per MWh in New England;
- Can$ 43 (US$ 34) per MWh (average and retrospectively) for smaller consumers in Ontario, though the provincial government made up the difference between the cap and the market price (at enormous cost to taxpayers);
- Can$ 110 (US$ 87) per MWh in Alberta;
- A$ 5,000 per MWh, rising to A$ 10,000 (US$ 7,800) per MWh in 2002, in Australia.

In the UK the regulator (then Offer) imposed a cap on average pool prices between 1994 and 1996. In 1999-2000 Offer's successor Ofgem tried to acquire special powers to investigate and cap individual price rises through a 'Market Abuse License Condition', though this was ultimately rejected by the Competition Commission.

Though price caps may on the surface seem an attractive weapon to use against abuse of market power, in practice their effects can be paradoxical, serving to put upward pressure on prices. Doug Biden, of the Electric Power Generation Association in the USA, for example, has argued that price caps in the PJM market are the primary reason why there are fewer retail suppliers competing in the marketplace than expected[73]. Further, 'price caps insulate customers from the market, removing incentives for customers to respond to market price signals and reduce consumption when needed'.

The system of price caps that pervaded the whole Californian market at various times played a major part in the crisis of 2000/1. Capping contributed to the crisis in at least three ways. Most directly, it insulated consumers from changes in the costs of electricity generation. The firms which had real-time meters could have responded to higher prices by cutting elements of their load, but even those which did not would have been aware of the significant impending price increases in the near future and could alter their operations accordingly, either before or when those prices came through in their bills. The potential reduction in demand is difficult to determine accurately but would undoubtedly have mitigated the capacity shortage. It would also have had an effect on the price that the Utilities were paying for the vast bulk of their power.

Secondly, the retail price cap was instrumental in pushing the utilities into insolvency. In such circumstances, many of the independent power producers which had contracts to supply the Utilities stopped doing so for fear of not being paid.

Thirdly, as the gas price increased some generators found themselves facing fuel costs higher than the cap at which they could sell power and so withdrew from doing so. Others chose to sell their electricity into other western region markets without similar a price caps. Some closed down capacity within California because they owned generators in other States and could export electricity to California, so by-passing the

[73] http://www.epga.org/testimonyMar04.html, Biden D. (2004), Testimony of Douglas L. Biden, President, Electric Power Generation Association before the Pennsylvania House of Representatives Consumer Affairs Committee Wednesday, March 3, 2004 on Electric Deregulation.

cap. Some even exported power and reimported it, placing extra strain on the transmission system and wasting electricity by transporting it over unnecessarily large distances, a practise known as 'megawatt laundering'.

Other examples of unpredictable government intervention include the imposition by one UK industry minister, Peter Mandelson, of a moratorium on new CCGT in 1998 to protect the mining industry, which was lifted by his successor, Stephen Byers, in 2000: and the decision taken in December 2003 by the Irish energy regulator to halt connections of windpower to the Irish grid because of fears about system stability (lifted the following May).

More recently, Ofgem published recommendations for yet another radical reform of energy policy to 'ensure secure, affordable and sustainable energy supplies in the decades ahead'[74]. Ofgem offered five alternative options:

- Targeted reforms – minimum carbon price; increasing fines for gas and power producers for not providing supplies contracted to the market, therefore encouraging investment in generation capacity; improving demand side response, including smart meters in homes encourage efficient energy use, to reduce demand during peak times.

- Enhanced obligations – energy suppliers obligation to cover future demand of their customers against some pre-defined security standard; gas and power system operator obligation to purchase sufficient back-up gas and flexible power generation for future demand; obligation for all combined cycle gas turbine (CCGT) to be able to run a certain number of days on back up oil distillates fuel, therefore decreasing gas demand in certain days; introduction of centralised renewables market for wind and other variable renewables, to reduce green generator risks of price spikes and to help balance the grid, as seen in Spain.

- Enhanced obligations with renewable tenders – replace existing Renewable Obligations (RO) for tenders for renewable capacity (introduced with gas and power generators' obligation to provide future energy production capacity in mind).

- Capacity tender – increasing fines for undersupply of gas or power, improved demand side response; a centralised renewables market; tenders to be offered for a range of long-term power generation projects, including clean coal, nuclear, as well as renewables; tenders for gas storage and infrastructure projects.

- Centralised buyer – a central buyer of energy, with all future power and gas investments directed through a single entity.

The range includes relatively minor tinkering with the market, through regulatory requirements over such issues as available capacity and 'security standards', to in effect to a reintroduction of central planning. Once again, major and unpredictable changes in the market structure were being proposed to deliver social goals, with incalculable but presumably significant effects on the confidence of investors.

[74] http://www.ofgem.gov.uk/MARKETS/WHLMKTS/DISCOVERY/Documents1/Project_Discovery_FebConDoc_FINAL.pdf, Ofgem (2010), Project Discovery; options for delivering secure and sustainable energy supplies.

Such actions, and their consequences, lend powerful support to the view that, if electricity supply is to be provided through the operation of market forces, it is important actually to let the market work and follow its own logic. Not to do so may well result both in operational paradoxes such as those outlined above and in powerful disincentives to investment in new capacity. In the words of Bill Eastlake of the Idaho Public Utilities Commission[75]:

> ‘If you believe in markets you can’t blanch at the sight of victims.’

Or in more measured language:

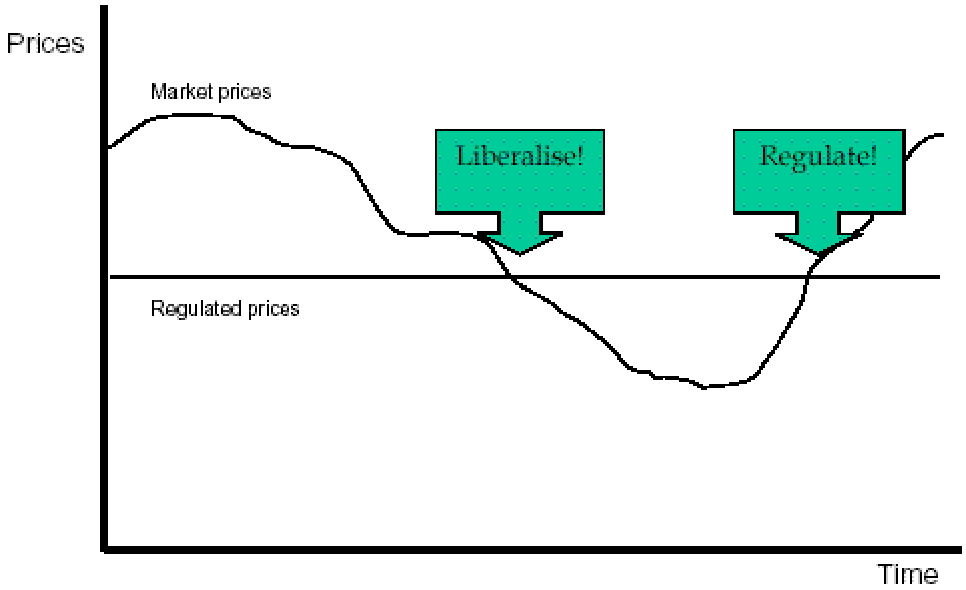
> ‘Failure can be a sign that competition is working effectively, because in many cases it is the degree of rivalry between companies and the extent to which customers exercise choice that inevitably leads to success for some and failure for others[76].’

The crucial practical question is this: will the political establishment ever have the stomach to allow such a free hand to market forces?

Put at its most cynical, one can imagine the emergence of an ‘opportunistic regulatory cycle’. As projected market prices fall below the regulated price – perhaps because of significant plant overcapacity, when competition based largely on short-run marginal cost can be introduced without affecting security of supply – governments will tend to liberalise the power market. As the market price creeps up towards and exceeds the projected regulated price, perhaps because of repeated price spikes caused by a shortage of capacity at times of high demand, the temptation will be for governments to reregulate, so robbing the investor of the payback on their original investment.

[75] Los Angeles Times (December 9, 2000), ‘How State’s consumers lost with electricity deregulation’.
[76] http://www.ofgem.gov.uk/temp/ofgem/cache/cmsattach/292_2sep01.pdf, Ofgem (2003), Consideration of responses to the consultation document: Supplier of Last Resort - security cover and levies.

Figure 16: Schematic of an Opportunistic Regulatory Cycle[77]



An example was played out in the gubernatorial race in Maryland in 2006. BGE (Baltimore Gas & Electric) proposed a 72 per cent increase in electricity charges, largely as a result of Hurricane Katrina, instability in the Middle East and increased demand for gas from developing nations such as China. Democrat and Montgomery County Executive Douglas M. Duncan called for price caps on Maryland electricity rates and reregulation of the industry, following similar demands from members of the State legislature. His opponents, Governor Robert L. Ehrlich Jr and Mayor Martin O'Malley, while not taking such an extreme stance, took high profile positions in 'negotiating' with BGE to reduce the increase. Richard Sedano, director of the Regulatory Assistance Project, an energy policy think tank in Vermont, reflected once again the fundamental ambiguity over the nature of electricity companies in competitive markets[78].

> 'A utility is a public service company, and if the legislature decides to change the task of the company, they can do that. Hopefully, they won't do it willy-nilly and they won't do it that often.'

Against such a background the rational action for consumers in the short-term would be not to pay higher power prices until investment flowed back into the system but instead to develop lobbying mechanisms to ensure that government would never allow the prices to reach those levels.

Another mode of intervention is the periodic introduction of subsidies or guaranteed market tranches for Ministers' favourite technologies. The choice of the word

[77] http://www.nera.com/wwt/publications/3730.pdf, Shuttleworth G., NERA (2000), Opening European electricity and gas markets.
[78] http://www.dougduncan.com/newsroom/060418-tricity?t=5, Green A. (2006), Duncan pushes power plan, Duncan, Simms for Maryland website (April 18, 2006).

'aspiration' in the 2003 Energy White Paper (later superseded by firmer targets) to describe the UK government's desire to see 20% of electricity generated by renewables in 2020 was a fine example[79]. By avoiding the word 'target' at that time (which could presumably have lead to the government being held to account) the impression was given that the enormous support necessary to reach this figure might not have been forthcoming, so potentially deterring investment in renewables. But the existence of the aspiration, implying that government might intervene further to support renewables after all (and indeed subsequently has done), was likely to deter investment in other energy sources which may find a portion of their potential market closed off.

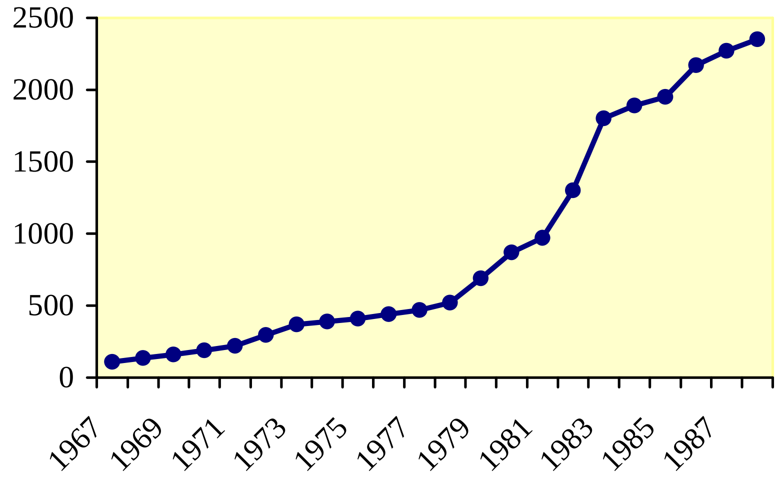
Whether or not a particular government or regulator would actually act to cap the very high power prices which would be necessary to send signals for new investment, or intervene in some other way in pursuit of social or political goals, is perhaps not the main point. While it remains credible that governments or regulators *might* behave that way – and it is hard to see how such an impression could ever be dispelled, especially in the light of past experience – it will affect the perceptions of potential investors. The risk of interference will lead to an increase in the cost of capital by increasing the rate of return demanded on new investment, with the likely effect of driving out that investment or delaying it until matters become clearer.

Nuclear energy in competitive markets

Most of the world's existing nuclear capacity was ordered and financed within a command-and-control paradigm. 'Generation II' nuclear plants, such as were being constructed in the 1970 and 1980s, were characterised by large size (1 GW plus by the late 1980s) and very heavy initial investment costs, a profile which benefited heavily from the long pay-back periods and relatively low rates of return typical in monopolistic command-and-control electricity systems. However, the absence of market discipline was probably a factor in the enormous inflation in cost of nuclear plant being built over that period.

[79] http://www.berr.gov.uk/files/file10719.pdf, BERR (2003), Our energy future - creating a low carbon economy.

Figure 17: Overnight Costs of Nuclear Power Stations, USA ($ millions)[80]



It is an open question as to whether nuclear energy would have developed, and if so in what form, in a competitive market environment. In a more stringent economic environment where costs could not be passed on to captive customers plants may well have been both smaller (to create more flexibility) and with more emphasis on bringing down construction and operating costs.

It is claimed that Generation III nuclear plants such as the AP-1000, EPR-1600 or ACR will be significantly cheaper to build than their predecessors, although recent experience has cast some doubt on this claim.

As a benchmark, the five units completed in Japan and Korea between 2004 and 2006 suggest overnight costs of between $2,357 and $3,357 per kW with an average of just under $3,000 per kW (expressed in $2007)[81].

Estimates of the initial investment costs for new ('Generation III') reactors have been growing steadily through the decade. In 2004, for example, the US Senate Committee on Energy and Natural Resources, referring to the Westinghouse, A1000, reported:[82]

> 'The industry estimates the capital cost of the first few nuclear plants built would be in the range of $1,400 per kilowatt. After these plants are built and the first-of-a-kind design and engineering costs have been recovered, subsequent plants of the series will have capital costs in the $1,000-$1,100 per kilowatt range, which is fully competitive with other sources of baseload electricity.'

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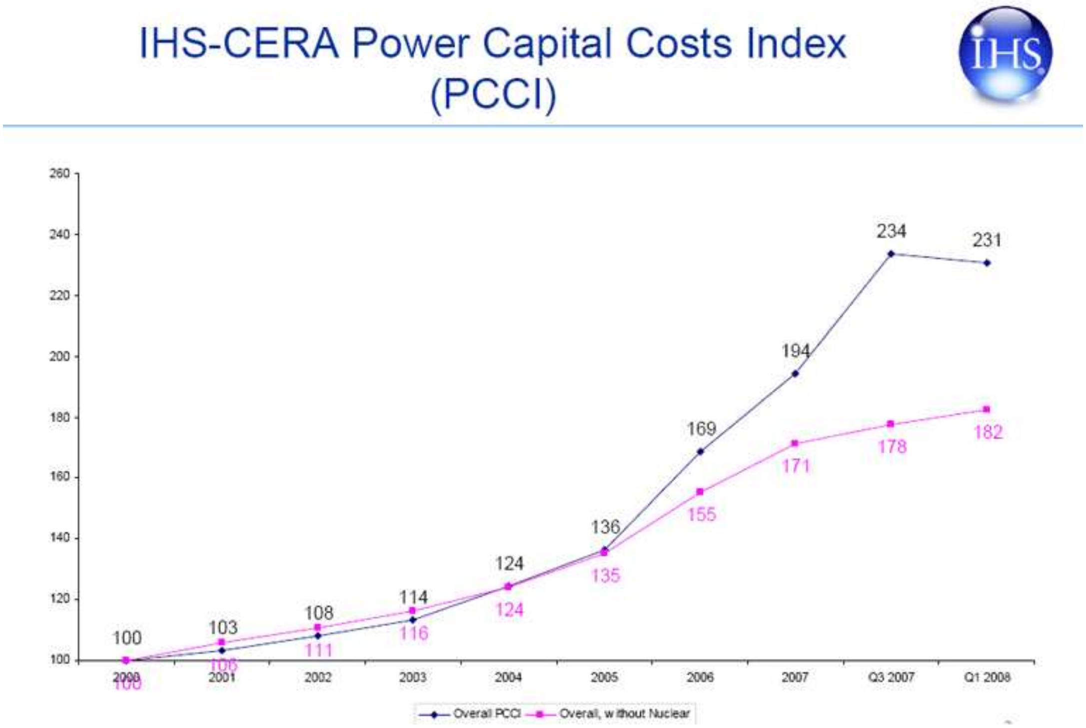
[80] http://www.phyast.pitt.edu/~blc/book/index.html, Cohen B. (1990), The nuclear energy option, Plenum, New York.
[81] http://tisiphone.mit.edu/RePEc/mee/wpaper/2009-004.pdf, Du Y. and Parsons E. (2009), Update on the cost of nuclear power, Centre for Energy and Environmental Policy Research, MIT.
[82] http://bulk.resource.org/gpo.gov/hearings/108s/93750.pdf, Committee on Energy and Natural Resources, United States Senate (2004), Hearing before the Sub-Committee on Energy to receive testament regarding new nuclear power generation in the United States.

There has been considerable general inflation in power plant construction costs (all fuels) in the USA in the course of this decade[83]. A plant costing $1 billion (in constant 2000 money values) in 2000 would have cost $2.31 billion in May 2008, representing an average increase of some 130%. Non-nuclear increases amount to an average of 82%, suggesting a significantly higher projected proportional increase for nuclear projects.

[83] http://seekerblog.com/archives/20080827/cera-construction-costs-for-new-nuclear-plants-up-over-230-since-2000/, Darden S. (2008), 'CERA: construction costs for new nuclear plants up over 230% since 2000', Seeker Blog website.

Figure 18: HIS-CERA Power Capital Costs Index (PCCI)



Among the factors behind these increases is high ongoing demand for new power generation facilities worldwide, leading to cost increases, supply issues and longer delivery times as manufacturers struggle to keep up with demand. According to Moody's, dramatic increases in commodity prices over the recent past, exacerbated by a skilled labour shortage, have led to significant increases in the overall cost estimates for major construction projects around the world. In the case of new nuclear, the very detailed specifications for forgings and other critical components for the construction process can add a new element of complexity and uncertainty. Labour is in short supply and commodity costs have been extremely volatile. Most importantly, the commodities and world wide supply network associated with new nuclear projects are also being called upon to build other generation facilities, including coal as well as nuclear, nationally and internationally. Nuclear operators are also competing with major oil, petrochemical and steel companies for access to these resources, and thus represent a challenge to all major construction projects[84]. For example, there are only two companies that have the heavy forging capacity to create the largest components for new nuclear plants – Japan Steel Works and Creusot Forge in France. The demand for heavy forgings will be significant because the nuclear industry will be competing with the petrochemical industry and new refineries as well as other electricity generation projects.

The estimated costs for new nuclear power plants in the USA begin to increase significantly in the second half of the decade[85]. A June 2007 report by the Keystone Centre estimated an overnight cost of $2,950 per kW(e) for a new nuclear plant

[84] Moody's Investor Services (2007), New Nuclear Generation in the United States: keeping options open vs addressing an inevitable necessity.
[85] http://www.synapse-energy.com/Downloads/SynapsePaper.2008-07.0.Nuclear-Plant-Construction-Costs.A0022.pdf, Synapse Energy Economics (2008), Nuclear power plant construction costs.

(between $3,600 per kW and $4,000 per kW when interest was included)[86]. In October 2007, Moody's Investor Services estimated a range of between $5,000 per kW and $6,000 per kW for the total cost of new nuclear units (including escalation and financing costs) but expressed the opinion that this cost estimate was 'only marginally better than a guess'[87]. Also in October 2007 Florida Power and Light (FPL) announced a range of overnight costs for its two proposed nuclear power plants (total of 2200MW) as being between $3,108 per kW and $4,540 per kW. FPL estimated the total cost of the project (including escalation and financing costs) as being between $5,492 per kW and $8,081 per kW, giving a projected total cost of $12.1 billion to $17.8 billion for two 1100 MW plants[88]. Progress Energy, which filed an application for new build at Levy, Florida, projected a cost of about $10.5 billion for two new nuclear units, with financing costs bringing the total up to about $13-14 billion[89]. Georgia Power has estimated that the cost of its 45% share in two proposed nuclear plants at Vogtle would be $6.4 billion, consistent with Progress Energy's estimates[90].

Recent nuclear construction costs estimates in the USA can be summarised as follows:

Table 4: Recent construction costs estimates in the USA

Forecast	Overnight cost ($ per kW)	Total plant cost ($ per kW)	Total plant cost – two 1100 MW units ($ billions).
USDoE (2002)	1,200 1,500		
MIT (2003)	2,000		
Keystone Centre (2007)	2,950 2,950	3,600 4,000	
Moody's Investor Services (2007)		4,000 6,000	
Florida Power and Light (2007)	3,108 4,540	5,492 8,081	12.1 17.8
Progress Energy (2008)		6,360	14.0
Georgia Power (2008)		6,500	6.4 for 45% stake

Olkiluoto-3 in Finland, a 1600MW Areva EPR design expected to cost some €3 billion and to be available in May 2009, was by late 2009 running some three years behind schedule with projected final costs of €4.7 billion ($7 billion, or $4,400 per kW). The costs of the Flamanville-3 EPR in France were restated at €4 billion ($6 billion, or $3,500 per kW) in December 2008, from an original €3.4 billion just a year earlier. At the same time in Taiwan, the two Advanced Boiling Water Reactors (ABWRs) under construction at Lungmen were five years behind schedule and costs had risen from an

[86] http://keystone.org/files/file/about/publications/FinalReport_NuclearFactFinding6_2007.pdf, The Keystone Centre (2007), Nuclear Power Joint Fact-Finding.
[87] Moody's Investor Services (2007), New Nuclear Generation in the United States: keeping options open vs addressing an inevitable necessity.
[88] Scroggs S. (2007), Direct Testimony and Exhibits on behalf of Florida Power and Light in Docket No. 07-0650.
[89] Nuclear Engineering International (2008), 'Power market developments – the American way', June 18, 2008.
[90] http://www.climateark.org/shared/reader/welcome.aspx?linkid=99329, Smith R. (2008), 'New wave of nuclear plants faces high costs', Wall Street Journal, May 12, 2008.

initial $3.7 billion to between $7.4 billion and $9.1 billion ($2,750 to $3,400 per kW) in mid-2008[91].

At these cost levels it looks extremely unlikely that 'merchant' nuclear power plants, built as individual projects without long-term contracts in place in the hope of attracting a market for output at appropriate prices, would be attractive to investors. However, two alternative funding models which might be viable in competitive markets have emerged.

In Finland, Olkiluoto-3 is being financed by TVO, a consortium of forest industry and public energy companies, its biggest owners being energy company Fortum and forestry companies UPM Kymmene and Stora Enso. TVO is in effect an autoproducer, generating electricity for its shareholders rather than selling electricity directly. Shareholders take electricity at cost of production in proportion to their holding, in effect creating a guarantees market for TVO's output not dissimilar in essence to the long-term contracts with electricity suppliers in a command-and-control system. (It should be noted, however, that because Olkiluoto-3 was the lead plant for the EPR-1600 design, Areva, the manufacturers, offered a low price, in effect retaining a considerable amount of the risk as a payment for the experience it would gain from the project and the financial advantage of having a plant to showcase.)

The other funding route within liberalised markets involves very large, cross-national electricity generating companies which can fund a range of new products from a mixture of equity and borrowing, either alone or, more likely, in consortium. For example, the Flamanville-3 reactor in France is being funded mainly by EdF but Enel, the Italian electricity giant, has a 12.5% stake. In the UK, a consortium involving Iberdrola (Spain), GdF Suez (France) and Scottish & Southern Energy has purchased a potential nuclear site in Cumbria, while RWE and E.On have joined forces to investigate building reactors at Wylfa on Anglesey, Wales and at Oldbury in Gloucestershire. EdF, widely regarded as having the most developed plans to finance new nuclear plants in the UK, formed an alliance with Centrica to buy British Energy, the company operating most of the UK's existing nuclear stations, and in late 2009 announced plans to form a wider consortium involving large energy users, along the lines of the TVO model[92] and the Exeltium consortium in France which includes companies such as Air Liquide, Rio Tinto Alcan, ArcelorMittal, Arkema, Rhodia and Solvay[93].

Nuclear energy represents a stark example of the dangers of trying to ride the twin horses of central control and market mechanisms at the same time. Notwithstanding the above caveats, in a command-and-control system nuclear energy has often tended to look attractive – at the low rates of return required for public or investment in monopolistic markets (typically about 5 per cent) it would appear to be the most economic method of generating electricity in most developed countries over the lifetime of the plant in most scenarios of fossil fuel prices[94]. At least at the fossil fuel prices that

[91] http://www.synapse-energy.com/Downloads/SynapsePaper.2008-07.0.Nuclear-Plant-Construction-Costs.A0022.pdf, Schlissel D. and Biewald B. (2008), Nuclear power plant construction costs, Synapse Energy Economics Inc.

[92] http://business.timesonline.co.uk/tol/business/industry_sectors/natural_resources/article6952723.ece, Pagnamenta R. (2009), EDF seeks UK backing from industry for nuclear plants, The Times (December 11 2009).

[93] http://www.gide.com/front/EN/actualites/communique_details_PAR_Exeltium_09_08.htm, Gide Loyrette Nouel (2008), 'Gide Loyrette Nouel advises Exeltium on discussion with the European Commission concerning the implementation of procurement and electricity-supply agreements', Gide Loyrette Nouel website (September 18 2008).

[94] http://www.iea.org/bookshop/add.aspx?id=196, IEA (2005), Projected costs of generating electricity – 2005 update.

pertained in 2007/8, even at more commercial rates of 10 per cent the new generation of nuclear plants still looked attractive in countries in which regulation has been stable and predictable and governments have given clearer and more consistent signals as to their attitude towards the electricity supply systems, such as France, Finland and the Asia-Pacific region[95], though again there are other factors, notably the size of the French champion EdF and the special terms offered to TVO by Areva for Olkiluoto-3. The emergence of new funding mechanisms suggest that there may be no inherent reason why liberalised markets cannot sustain nuclear investment, though there may need to be changes to the technology to all this to happen.

But in those countries in which there is a strong suspicion that government may be unable to resist interfering, nuclear investment still looks risky, perhaps unmanageably so[96]. To lose an investment of the size required to build a nuclear plant because of unpredictable regulatory action by future governments not yet elected might prove a risk too far. Various approaches have been pursued to address this – for example, in the USA significant incentives for new commercial reactors were included in the Energy Policy Act of 2005, including production tax credits, loan guarantees and insurance against regulatory delays,

Forward not back?

None of this analysis necessarily offers much comfort to those who long for a return to the days of the Central Electricity Generating Board. The command-and-control model in practice often failed to deliver on its alleged advantages. Most notably, isolated from competitive pressures, the underlying costs of power production were high. It is difficult to escape the conclusion that investment decisions were often taken on the basis of a visceral attraction to the technology in question (or hatred of the alternatives) – nationalised industries were often run by people who had made their way up through the technical side of the business[97]. Managers' practice of 'picking winners' (or, just as often, losers) rather than testing decisions against market criteria delivered great power into the hands of those with most influence with government rather than necessarily those with the best commercial case. It was often policy to pursue a diversity of supply sources and an excess capacity margin (reaching 45% in Canada, 50% in Spain and 70% in parts of Australia) in order to guarantee secure supplies against unexpected occurrences. The general laxity which often besets companies operating in a monopoly situation (in which the pressure to reduce or contain costs is weakened by the absence of consumer choice) was also in evidence – for example, success in collecting payment for electricity and preventing theft varied significantly from country to country.

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[95] The issue of discount rates is itself far from being a purely 'technical' economic matter. 'Social' discount rates as used by government planners, typically around 3.5%, contrast with commercial rates of 10% or more. For nuclear energy (and many renewables), with its very heavy initial investment costs, this is a crucial issue – trebling the discount rate more or less doubles the cost of nuclear-generated electricity but has a much smaller effect on the costs of CCGT-fired electricity, for which the fuel price is proportionally far higher and the capital cost correspondingly lower.

[96] In the most extreme example, the Shoreham plant, Long Island, New York, was completed in 1984 at a cost of several billion dollars but was never granted an operating license, being sold for decommissioning in 1989. See http://www.newsday.com/community/guide/lihistory/ny-history-hs9shore,0,563942.story?coll=ny-lihistory-navigation, Fagin D. (1995) , Lights out at Shoreham – anti-nuclear activism spurs the closing of a new $6 billion plant, newsday.com.

[97] It should however be noted that there is a mirror-image downside risk in commercialised electricity markets that few if any of the top team may have relevant technical experience, leading to a potential mismatch between commercial desirability and technical possibility.

In the UK the system did not even deliver diversity of fuel supply. The monopolistic Central Electricity Generating Board came under enormous pressure from successive governments to use domestically-mined coal for the bulk of electricity production – as late as 1990 British-mined coal was still responsible for 65% of electricity supplies. Such a policy delivered disproportionate political power to the National Union of Mineworkers which on several occasions was able to take on the government of the day by causing or threatening widespread power outages.

This being said, the CEGB could claim major successes. Security of supply, notwithstanding problems with the miners, was impressive, notably in the very rapid recovery from the storms of October 1987. Timely investment in new generating capacity was forthcoming (indeed, as noted above the problem was more one of over-investment than under-investment), an important achievement in view of the very high costs associated with power outages or severe degradation of the quality of supply. Further, a command-and-control model can, in principle, deliver environmental objectives in a relatively straightforward manner, by central dictat over the sources of generation.

But the dichotomy remains. The competitive model, which treats electricity as a commodity, requires government to follow a rigorously hands-off approach to the marketplace (once the basic framework has been established) and to resist the temptation towards short-term meddling for political reasons. The command-and-control model, which views electricity as a social service, requires government to retain (and indeed to use) a range of interventionist measures to direct the market to deliver non-economic goals. The former, if left to its own devices, should over an investment cycle deliver economic supplies of electricity, although there will be times of high prices (necessary to send signals for new investment) and security of supply (and perhaps environmental outcomes) may be shakier than in the command-and-control model. The latter model should deliver plenty of new investment and safeguard secure supplies, but with the penalty of higher than necessary costs.

The problem of following the current confused half-way-house is that the outcome may well combine the worst of the other models – a blight on investment resulting in threats to secure supplies coupled with long periods of high electricity prices owing to a shortage of generating capacity – rather than the best. Present muddled policy is resulting in incoherent policy outcomes. It seems paradoxical that energy sources such as windpower, whose intermittency creates challenges in terms of security of supply and therefore the need for back-up capacity in real time, are receiving enormous effective subsidies in countries such as Germany, Spain and the UK. (Even when the wind is blowing someone somewhere will have to be keeping gas-fired capacity ready, using fuel, producing greenhouse gases and paying the workforce, to take over in an instant if windspeeds change adversely.) Yet sources of electricity such as nuclear energy, in some ways a more attractive option for reducing greenhouse gas emissions (not for example requiring weather conditions to be favourable), are subject to the UK 'Climate Change Levy', an economically inefficient way of encouraging emission reduction (since it treats heavy carbon emitters like coal, medium emitters like gas and very low emitters like nuclear the same). There are those who suspect this is more a matter of the politics of appeasement (directed towards the Left of the Labour Party) than of rational calculation. A 'technology-blind' approach, focused on outcomes rather than the particular fuels used to get there, might be more defensible in objective terms. But it is the very ubiquity of such political factors, sometimes very short-term in nature, that casts doubts on the practical ability of governments to allow markets to work.

To summarise, if governments have the courage, as the Norwegians did in the winter of 2003, to ride out the short-term crises without introducing panic measures like price caps which destroy investor confidence then the liberalised model may well be the most attractive when taken in the round. But without such resolve a half-hearted attempt at liberalisation may be worse than central planning (or at least a more enlightened version than was generally on offer in the 1970s).

POLICY RECOMMENDATIONS

- The new coalition government should decide, and make clear, the extent to which it regards secure power supplies as a matter for the marketplace (while setting an appropriate and stable role for regulators in shaping market rules to encourage environmental protection, maintenance of appropriate capacity margins, e.g. by considering the option of capacity markets or capacity payments), accepting that very high power prices may not be reflective of abuse of market power but may be necessary to send the signals for new investment; and the extent to which it intends to allow social and political considerations to take precedence.

- The government should ensure that the locus of decision-making is clear, not suggesting simultaneously for example that it has decided that there should be a new programme of nuclear stations or offshore windfarms and that that decision is not one for governments at all.

- The governments must ensure that planning and regulatory procedures cannot be used by opponents of a particular technology, or of electricity generating technology in general, to delay projects and push up their costs to the extent that they become effectively impossible in a competitive environment, irrespective of the objective merits of such projects.

- The governments must recognise that, should it wish to pursue an interventionist stance in order to promote political priorities and hence intervene more or less capriciously in markets (e.g. setting price caps at constantly changing levels), it may well damage the confidence of investors to commit to funding new generating capacity at the appropriate time. Appropriate schemes of compensation for power generators which lose income because of regulatory action, such as those offered in the 2005 Energy Act in the US, may be a workable adjunct to interventionism, but may not be as efficient as allowing market forces to do their job.