Looking ahead: future market and business models

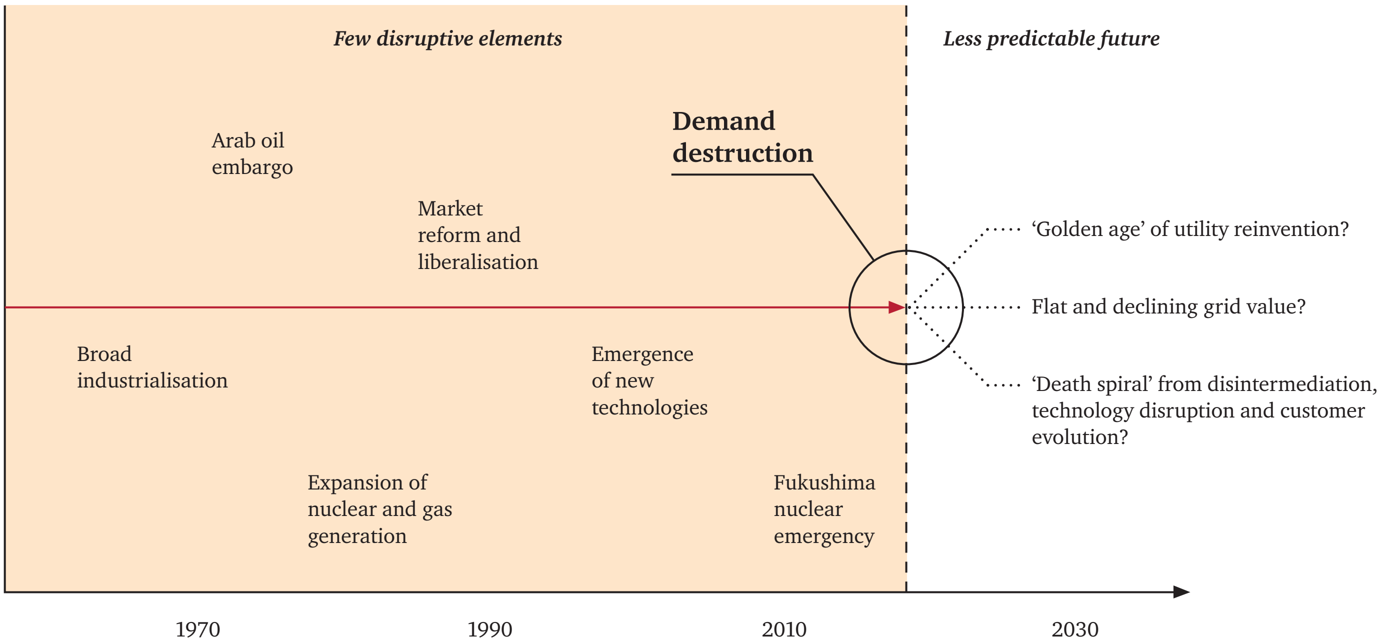
No-one can predict the future but it is important that companies take a clear view on the ways in which their marketplace is likely to evolve and their company's place in the various different possible scenarios.

PwC's energy transformation programme includes joint activities with companies to support their future strategies and map out the risks and opportunities involved.

At its heart, this means addressing key questions such as:

- What will future market design look like?
- What are the implications for my company's purpose, role and positioning?
- What are the business models that I need to pursue?
- What are the implications for people and operational change?
- What will existing and new competitors be doing?
- How best to continue to deliver shareholder value throughout the transformation process?

Figure 2: The power sector has reached an inflection point where its future direction is much less predictable



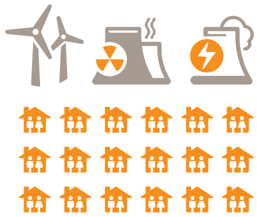
Future market designs

We foresee a number of market models emerging. Unlike markets for many other products and services, the role of governments is significant given the importance of power to everyday life and economic activity. So the exact market shape for individual countries will depend on policy direction as well as on other local factors such as the extent of competition and customer choice, access to fuel, the nature of existing infrastructure, the degree of electrification and degrees of interconnectedness or isolation from neighbouring territories. And, of course, a crucial factor will be the pace of global technological change.

'Business as usual' with the maintenance of a classic centralised 'command and control' energy system may continue to be an option for some countries, although we expect to see an increased focus on technology and innovation as this model develops. But already over the last two decades or so, many countries have moved away from this 'classic model' and, through a combination of regulator-led and market-led innovation, have created markets characterised by different ownership structures with varying degrees of market liberalisation, customer choice and technology adoption.

Current change has so far, on the whole, been incremental and stopped short of 'transformative change', although many would see aspects of current developments in Europe as transformative. But we believe that, if the pace of innovation leads to widespread adoption of renewable and smart energy technologies, we are likely to see the emergence of a number of new market models. Each market scenario can be described by a unique set of characteristics and illustrates different points along a series of transformation curves. We have considered a wide range of characteristics in developing the scenarios, including ownership structures, the level of adoption of renewable technology, level of deregulation, level of engagement in the wholesale market by customers, regulatory and policy involvement in market structure and operations, use of digital media and the mix of large-scale and small-scale generation.

We outline below four new market scenarios which represent transformative change – a significant shift from where we are today. Power utility companies are unlikely to be in only one of these scenarios but, instead, experience a blend of them with perhaps one being dominant. The most appropriate path for any given company will depend on local, as well as global, factors.



Green command and control

The Green Command and Control market scenario represents a market in which government owns and operates the energy sector and mandates the adoption of renewable generation and digital technology.

In this scenario, we see vertical integration as the norm (particularly between generation and retail), and investment decisions made as a response to regulatory direction. It is a market in which renewables may be cost-competitive or supported under renewable policy initiatives, whilst stranded thermal assets may remain operational even when private sector owners would have taken closure decisions. Ongoing capital investment would be subject to policy approval and would feed into regulated tariffs.

The market may combine a central grid with distributed networks where the latter support social policy initiatives such as rural electrification or reducing the level of capital investment in major transmission infrastructure. There is likely to be an increased level of investment in distribution networks to support back-up capacity in localised areas of the grid. Consumer tariffs will reflect policy decisions and recovery of stranded costs, and may be smeared across central and distributed networks.

There may be some limited opportunities for new market entrants – potentially as outsource partners supporting state-owned companies with operations of distributed networks, or as compliance advisors to the regulator supporting tariff determinations and investment case business approvals. Outsourcing support opportunities might offer local small-scale as well as large project opportunities. For example, in South Africa the Department of Energy has mandated the roll-out of a national solar water heater programme with the goal of one million installations on households and commercial buildings over a period of five years, providing significant potential for local capacity-building.

How might this market arise?

We see two routes. In the first, it might develop directly from a traditional, centralised "classic model" where the government takes policy decisions to invest in renewable generation, smart technology and local energy hubs. In the second, the market may have undergone some degree of liberalisation and/or new entrants in generation or retail, but policy decisions result in control reverting to the public sector. This might be the case, for example, in the event of a political decision to renationalise or when a company fails and private sector entities are not prepared to step in.

We would see private sector players exiting the market and may see mergers of generators and/or retailers to support government policy preferences (for example, a state-owned generator operating stranded assets as back-up for renewable generation, another state-owned company operating small-scale renewable generation and supplying customers within distributed networks).

Which countries might adopt this market scenario?

In our view, a green command and control market scenario is most likely to evolve in markets where there remains significant public ownership, single-buyer models or limited interest from the private sector in investment, e.g. in China, selected South American, Middle Eastern and African markets. Further, in some countries, renewable energy dominates the energy mix, such as hydropower in Bhutan or Norway. In such situations, it makes sense for governments to encourage green power for own use, thereby reducing any import of fossil fuels, and for earning extra revenue from export of green power.

Ultra distributed generation

The Ultra Distributed Generation (DG) market scenario represents a market in which generators have invested in distributed renewable generation, with investment decisions based on policy incentives and/or economic business cases. It is a market with full unbundling and strong customer engagement, both in retail and as micro-generators.

Market operation becomes more complex for both transmission and distribution operators, given the increased volume of distributed and renewable generation and the continued operation of large-scale thermal generation, but remains centrally operated and does not fragment. Regulatory oversight and revenue price controls are likely to address efficiency of system operation and equitable treatment of generation in dispatch and system support. In particular, determining which market participants pay for the central transmission grid becomes a critical regulatory question.

We expect to see stranded thermal assets as distributed resources become cost-competitive and, in part, due to the lower flexibility of some distributed generation and the ensuing volatility of wholesale prices. Risks to security of supply increase and we are likely to see continued policy and regulatory intervention to maintain an appropriate level of thermal capacity on the system. Generators with distributed capacity will have increased volumes of operational data to manage as they match their physical and trading positions. Retailers will need to continually review their trading and hedging strategies to manage price volatility and to determine the tariffs that can be offered to different categories of consumers – particularly prosumers who offset their demand through micro-generation.

This scenario presents considerable challenges for system operators with complexities such as reverse flows, voltage management, fault maintenance etc., placing even greater importance on data management capabilities. Generators, transmission system operators (TSOs) and distribution system operators (DSOs) will need to revisit the capability and skills required from their staff and we expect to see an increased emphasis on technology specialists over time.

There are significant opportunities for new entrants in addition to investment in renewable and distributed generation. We expect to see growth in participants providing aggregation services, both for small-scale distributed generation and for load management. Offshore TSOs or private sector, localised DSOs linked to a portfolio of distributed generation will become more prevalent. There may be new roles for managing the interconnection between local networks or for managing and interpreting generation data.

How might this market arise?

We see the main driver of this model being policy decisions which result in a significant increase in small-scale distributed capacity over a relatively short period of time. This might be led by retailers encouraging their consumers to reduce demand through becoming a prosumer owning micro-generation, by proactive consumers or by generators sizing investments to meet local community needs at a distribution grid level.

Integrated investments in new communities that include distributed generation and a back-up connection to the grid also support an Ultra DG market scenario. The Ultra DG model could also arise through an evolving spiral of developments, where there has been no conscious policy decision but investments over time have led to the closure of uneconomic thermal plant, prosumers reducing local demand requirements and rebalancing the system operations roles of the TSO and DSOs.

Which countries might adopt this market scenario?

In our view, an Ultra DG model is most likely to arise in markets where there is already significant investment in distributed generation but where there is a strong national infrastructure supported by policy objectives, e.g. Germany or California. It could also arise in markets where the opportunity for significant investment in small-scale renewables or larger-scale distributed generation could support local networks or isolated developments which would only require periodic back-up generation from the transmission grid, e.g. Middle Eastern markets or Australia.

Local energy systems

The Local Energy Systems market scenario represents a market in which we see significant fragmentation of the existing transmission and distribution grids and local communities demand greater control over their energy supply, or a market in which a local approach is adopted for serving remote communities.

The market is likely to have undergone full unbundling and experienced strong customer engagement, both as consumers and micro-generators, but recognises the benefits of vertical integration for off-grid solutions. Financial viability of distributed generation and distributed grids is a prerequisite. Strong policy support for fragmentation is required, either to allow local initiatives or to encourage and incentivise local communities and businesses to take control and build and operate their own local energy systems.

In its purest form, there would be a limited role for large-scale generation connected to a central transmission grid. It would continue to support industrial customers with large, secure, long-term loads and would be able to provide back-up for security of supply reasons. We would expect significant levels of stranded capacity, which may close without policy support.

We see generators focusing on developing and operating small, distributed generation assets, sized to support domestic communities or commercial customers and most likely connected to distribution networks. Tariffs may well vary across the country as the costs of supply would be based on the local generation assets. Customers may be able to invest in the generation assets so that they have an incentive to manage their demand at times when the local capacity margin is tight.

We see a need for new approaches to security of supply, which we would expect to be provided by DSOs in the main, providing interconnections between localised grids. The role for the TSO would be greatly reduced and would result in significant overcapacity in transmission.

The market provides a new set of challenges for the regulator, particularly in relation to a customer protection obligation. Regulators will need to address interconnections between local energy systems, review the risk of disconnection and put in place reporting oversight mechanisms to check that customers are not being overcharged. Where a territory has existing transmission capacity, the regulator might also need to determine appropriate charging mechanisms for the transmission grid, both in terms of which customers should pay and what proportion of the stranded capacity should be included.

There are a number of new roles that could arise within a Local Energy Systems market. Generators may wish to become local energy operators providing a full range of generation, network and retail services across a range of technologies. Technology companies are also likely to look at the option of becoming local energy system operators. Market participants may look at the opportunities to link the power and gas markets. Grid companies may decide to provide O&M services to micro-grids to maintain the capability and skill base required to support their stranded assets.

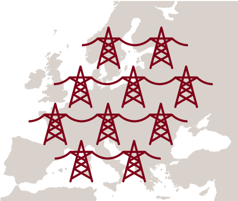
How might this market arise?

We see the main driver for Local Energy Systems to be policy decisions, based on an objective to increase rural electrification, reduce the emissions caused by using diesel generation in isolated communities or to deal with currently unreliable/intermittent supply. Coupled with technology improvements in electricity storage and reductions in the capital investment costs of solar and wind generation (for example), tariffs become affordable and Local Energy Systems become practical.

Which countries might adopt this market scenario?

We see Local Energy Systems as having most relevance in developing countries without a strong national transmission infrastructure. The fall in costs of renewable generation and the improved technology to support distributed grids means that isolated communities could be electrified without the need for major capital investment in transmission or fuel infrastructure. We would expect to see combinations of solar, wind, biomass and storage technologies used in these markets, for example in Africa, where a number of such systems have already been put into place. But in a country like India, where almost all generation capacity is grid-connected, local energy systems based on renewable energy are likely to be limited to island systems such as in the Sundarbans or Lakshadweep.

We see Local Energy Systems as being particularly suitable for isolated island systems, such as are found in Indonesia and the Philippines. The prerequisite is likely to be cost-competitive storage technology to support distributed renewable technology, CHP generation and limited thermal generation.
The benefits would be in replacing carbon-intensive diesel generation, for example in Alaska or the Philippines.
In India, a new local approach to energy is taking root in some states in the form of retail supply outsourcing, whereby the DSO contracts out part of its licence area to franchisees.



Regional supergrid

The Regional Supergrid market scenario represents a market which is pan-national and designed to transmit renewable energy over long distances. It is likely to embrace some degree of unbundling and customer choice. It requires large-scale renewable generation, interconnectors, large-scale storage and significant levels of transmission capacity.

The main challenge that will need to be overcome is regional regulation that applies across borders. National regulators will have limited responsibilities and will be required to oversee national markets within the regional context. In some situations, geopolitical risk will also be a major factor, for example if supply relies on generation located in neighbouring but politically sensitive regions.

We will see a new approach to generation investment decisions, where generators or governments will consider a regional merit order and interconnector access requirements as part of their business case assessment (for example, South Africa and the Democratic Republic of the Congo in the case of the Inga hydro dam project). The emphasis on large-scale renewable generation means that we are likely to see stranded thermal assets, which would require regulatory support to remain available for national or local grid support for security of supply reasons.

We will see a shift in approach from retailers, who will either become regional retailers or will enter into partnerships to access customers in other countries. Brand management and customer segmentation will become more complex as retailers embed their products and services in multiple countries.

Both generators and retailers will place an increased emphasis on trading and risk management. The presence of constraints, for example through limited interconnector capacity, means that locational pricing is the most likely outcome, so market participants will need to manage both national market prices and market prices in neighbouring countries.

The intermittent nature of some renewable generation is likely to mean volatility in market prices, particularly with long-distance transmission, and managing the pricing differentials between different countries will be crucial. Skilled regional traders will be vital, particularly for merchant generators.

National TSOs will enter into agreements with other TSOs in the region or, if agreement can be reached between countries, a regional TSO will manage the overall system. Decisions on where new transmission capacity is required to improve the efficiency of the system will be taken on a regional basis, and will require a new charter to be developed to lay out the objectives, rules and operational processes of the regional market. Distribution businesses will remain national or local but are likely to require restructuring so that their focus shifts to management of small-scale local renewables and of the interface with the transmission grid.

How might this market arise?

The main driver for a Regional Supergrid is policy, jointly created and pursued by neighbouring governments who recognise the benefits of harnessing renewable generation sources and linking them to distant demand centres. It could arise from market coupling initiatives, where the governments and regulators determine that each market would become more efficient and pricing signals would become more appropriate if the two markets became one.

Which countries might adopt this market scenario?

We see forms of a Regional Supergrid, but without common regulation in the USA, so there is the potential for further aggregation and adoption of common approaches. Looking at where a Regional Supergrid could arise through investment, we think that the Middle East has the potential to adopt this model. The EU has an objective of a single European electricity market which would effectively become a Regional Supergrid, but the complexities of implementing common regulation across multiple countries with different legal structures makes the pure model less likely to be achievable. A hybrid market adopting certain aspects would be a more realistic option.

India has proposed the development of a renewable energy grid, the 'Green Energy Corridor', with support from the German government. It aims to handle growth in renewable energy from the current 30GW to 72GW by 2022. In southern Africa, with the support of the Southern Africa Power Pool (SAPP) and the different utilities in the region, a supergrid called Zizabona is being established between Zimbabwe, Zambia, Botswana and Namibia, providing for the import/export of electricity via either PPAs or day-ahead trading through the SAPP.

Combined models

Each of the four potential market scenarios outlined above represents a transformative move away from current markets. There are common themes across the models and we can see how, in practice, countries might adopt certain components from more than one model.

The seeds are in place for transformative change but there is still a lot of inertia in the system. The pace of change will vary from territory to territory. Some will see a gradual evolution while others will see parts of the sector undergoing faster transformative change. Such transformative change might be defined by locality or by the part of the value chain.

We believe that these transformative energy market scenarios provide a future in which market participants and new entrants can thrive and the role of policy makers and regulators is clear. The most appropriate market scenario will come out of an assessment of the impact of the major disruptors and the local factors that apply in each individual situation.