Strategies and Business Cases for Smart Energy Networks

General introduction and specific regulations in the North Sea Region Countries

Report by the e-harbours expert group on Smart Energy Networks

Photo: Colourbox

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1 Introduction

The scope of this document is to give an overview about marketing strategies for smart energy networks. It intends to present concrete yet universal business cases that are applicable in most countries of the North Sea Region. In Chapter 2, the principles of these business cases are explained, together with information on general implementation and a short overview of costs, risks and benefits.

Chapter 3 gives and overview on how these universal business cases manifest in different NSR member countries in terms of general layout, regulative requirements and potential benefits. References to further information sources are provided. Also, country-specific business cases are presented that result from national regulations (e.g. feed-in tariffs for renewable energy).

1.1 What are smart energy networks, and why can they be profitable?

Smart energy networks are intelligent and flexible solutions that may combine demand side integration (see chapter 1.1.1), local generation of (renewable) energy and energy storage on different levels.
They include so-called Virtual Power Plants, where several dispersed consumers (and producers) are integrated, but also refer to energy solutions that are implemented locally at a single facility and behave smartly within the energy grid.

In general, the search for flexibility results from the necessity that within the electricity grid, demand and supply have to be kept at the same level at all times. In the traditional structure of the electricity system, this is achieved by adjusting the production to the changing demand. With the successive inclusion of renewable energy sources like wind and solar power, this becomes a challenge, as these sources are intermittent and cannot be regulated. One way to help the integration of renewables in the energy system is therefore to influence demand so that it follows the production curve more closely.

In this context, different business cases can be identified which exploit this flexibility. One group of business cases builds on the fact that the price of electricity (and/or for using the electricity grid) may vary with the changing supply and demand over time. By exploiting flexibility, consumers may thus reduce their electricity costs and producers can maximize their revenues.
In another group of business cases, flexibility is made available to grid operators who utilize it to directly support the electricity grid on different levels

An overview of the possible business models for smart energy networks is given in chapter 2.

1.1.1 What is demand side integration?

Probably the decisive characteristic of smart energy networks is the possibility to influence the demand of electricity. By flexibly shifting a part of the power consumption over time, the load profile can be optimized according to the requirements of the electricity grid and/or the electricity market. This is done by controlling the time when electric consumers are switched on and off, or by regulating their power consumption during operation (so-called modular control).

As all electric devices serve to support some sort of process or application (e.g. heating, cooling, lighting, ventilation, industrial processing etc.), their practical flexibility is constrained. For instance, though cold storage warehouses in harbour regions represent a great technical potential for demand side management, often the window of flexibility is restricted by the products stored. Critical, temperature controlled products mostly have very strict temperature limits and do not allow temperature variations. As a result the practical flexibility may be significantly lower.

Two basic determinants can be used to characterize the flexibility of single devices or entire properties:

- **Amount of shiftable load:**
  It describes the total amount of electric power that can be shifted on or off flexibly at a given moment compared to the baseline load. In most cases, this varies over the course of the day or also the workweek. Typical amounts in commercial and industrial properties that may justify economic exploitation reach from tens of kW to tens of MW.

- **Flexibility over time:**
  This describes how long a certain amount of load can be switched without negatively affecting the process or application the device is used for. To grasp this effect, it is helpful to imagine the respective process or application as a type of storage: It can go on without input for a certain time, but eventually has to be filled up again. On the other hand, if devices are switched on for too long a time, the process or application may not be able to absorb the additional input. Typical time spans for shiftable loads reach from several minutes to several hours, in some cases even weeks

Note that in many cases, these two determinants are interdependent, meaning that a big load is shiftable over a rather short time, or that a small amount of load may be shifted over a longer time. As a rule of thumb, the greater both the amount of shiftable load and its flexibility over time are, the more business cases become available and the higher the potential benefits from employing a smart energy network are.

1.1.2 How can local generation/storage capacities be integrated?

The presence of local electricity generation and/or storage capacity may greatly increase the flexibility and economic performance of a smart energy network - especially in the case of controllable generation, e.g. combined heat and power (CHP) devices or diesel-powered aggregates.

The basic rationale for activating own **flexible generation capacity** is whether the expected benefits outweigh the marginal costs (for fuel, operation, maintenance etc.).

In the case of CHP, however, thermal energy constraints are often limiting flexibility: Properties that rely on CHP have a certain, often fluctuating demand for thermal energy that has to be met, regardless of current benefits from electricity production. On the other hand, CHPs have to stop operating if no more heat can be absorbed by the property. A solution is to supplement the CHP with a heat storage tank that can store thermal energy and allows much greater flexibility in CHP operation. The heat can be buffered in a relatively easy way for later use (e.g. domestic or district heating), while the electricity is readily available in the VPP. This way the CHP unit becomes electricity driven and no longer heat driven.

If **intermittent generation capacities** are present (e.g. solar or wind power), effects on business cases are complex and also depend on national legislations. If no attractive feed-in tariff is in place, it may be attractive to use own production to substitute grid electricity, or to market it through other channels. However, if they operate under a feed-in tariff that is higher than even the peak electricity price, the best strategy is of course to feed all production into the grid without considering other options. Details are discussed in the country specific section in chapter 0. In order to fully integrate renewable generation into smart energy networks and to optimize planning, a sophisticated forecast of renewable generation may be necessary.

Direct storage of electricity faces the physical problem that electricity is more difficult to store than other types of energy, so that storage implies high losses and substantial investment costs. Therefore, it is currently not considered viable to add electricity storage capacity with the sole aim of increasing flexibility. Exceptions may be the specific situation in isolated power grids, for example on small islands, or the need for short term storage to reduce extreme load peaks.

Some smaller storage capacities are however already present in some industrial or commercial properties in the form of uninterrupted power supply units (UPS) or electric vehicle batteries. It may be considered to integrate such storage capacities into a smart energy network, i.e. to charge them in times of high/cheap energy supply and, if possible, use the battery reserve in case of energy shortage.

1.2 How are benefits of business cases calculated?

Potential benefits are usually calculated by comparing a baseline scenario to the assumed implementation of one or more business cases. For this, a demand response audit must be carried out where a first assessment of the economic potential is made, and the available flexibility (of generation, load and/or storage) is identified. Detailed data on the properties and/or generation capacities are needed (e.g. load/production profiles of a whole year and baseline energy costs/revenues) which will be combined with information concerning the electricity and gas contracts. Especially the calculation of load shifting potentials in complex processes or applications requires an in-depth analysis of the respective site, and ideally a model-based calculation and optimization approach.

A challenge is the high volatility of electricity markets, therefore, even if detailed historical market data is used, changing prices in the future may lead to significantly different results. Furthermore it is difficult to predict how some energy markets will evolve in the future and how revenues for certain business cases will develop.

1.2.1 Combining business cases for maximum benefits

In order to maximize profits and to achieve a short payback time for investments in smart energy networks, operators of smart energy networks should seek to combine several business cases.
For example, by shifting certain loads to off-peak periods, a property can shave its day-time load peaks to reduce grid utilization costs (see chapter 2.1.1), and at the same time procure electricity directly from the spot market to benefit from lower off-peak prices (see chapter 2.2).

However, as more business cases are implemented and more markets are served, the planning and optimization process gets much more complex: It has to be calculated for each time unit what combination of marketing option would yield optimal profits. Besides a potent optimization

algorithm, a sophisticated load forecast regime may become necessary, as well as price prognoses for the energy markets or weather information for forecasts of renewable energy production.
Also, not all marketing options can be served simultaneously. Especially sophisticated business cases like taking part in the reserve capacity market (see chapter 2.4) greatly limit the ability to participate in other markets at the same time.

Depending on the relationship between stakeholders, it may occur that two parties request opposite services or the same service from a smart energy network according to their specific interests. Examples of such conflicts are in particular:

- TSO (Transmission System Operator) and BRP (Balancing Responsible Party): As the responsibility of the TSO is to maintain the balance within his control area and the task of the BRP is to preserve the balance of his portfolio, it may occur that these players send out contradicting requests. The TSO may require a decrease in electricity consumption while the BRP sends out the signal to consume more to fully balance an increased production in his portfolio.
- TSO and DSO (Distribution System Operator): The request of a TSO to increase the consumption in order to restore the balance in its area of control can cause local congestion problems in certain parts of the distribution grid.

1.2.2 What costs and risks have to be considered?

Necessary **technical investments** for the implementation of a smart energy network vary greatly. The most important determinants are:

- Number and complexity of business cases to be served
- Type, number and location of devices to be managed (single consumer vs. multiple, dispersed consumers/producers)
- Existing monitoring/automatization infrastructure (e.g. energy management system) for devices and related processes
- Specific security/certification requirements

Other Costs for smart energy networks are:

- Initial demand response audit, including data measurement/analysis
- Development of operational concept for the smart energy network
- Costs during implementation: Training of technical and administrative personnel, clearing of financial and legal issues, prequalification/licensing process for different markets etc.
- Operational costs: Technical maintenance, monitoring and optimization, trading fees for certain markets, commissions in case of contractors/agents

Investment can therefore vary from several thousand to hundreds of thousand Euros. In this context, it is recommended to implement smart energy infrastructure (or at least the necessary technical components) whenever new facilities are constructed, existing ones are modernized or new processes are introduced. Thus, the basis for a smart energy solution is laid and later, cost-intensive retrofitting is avoided – given that flexible, decentralized and efficient energy solutions are key requirements in the future.

Risks in the implementation of smart energy networks are also present and should not be ignored:

- The risk of affecting local processes through load shifting can be minimized by the careful planning and implementation of safeguards. However, for some processes or facilities, the potential (financial) damage may be too high compared to the expected revenues.
- Energy markets are volatile; exact long-term prognoses are extremely difficult. Therefore, calculations of return on investment are difficult and may complicate larger investments.
- Regulations and structures of energy markets are constantly evolving, aggravated by the interdependencies of national and EU regulations. Also, laws regarding renewable energy subsidies, energy efficiency, climate protection etc. may have a large impact on SEN business cases and have to be watched carefully.

A possible safeguard for the implementation of smart energy networks is to rely on more than one business case, or at least to keep a later participation in other markets in mind when designing the smart energy network.

2 Universal business cases

2.1 Contract optimization

2.1.1 Reduce grid utilization costs

What does it mean?

Energy costs for large consumers above a certain yearly consumption consist of the commodity price per kWh and the capacity price. The latter is charged for grid usage by the distribution system operator (DSO) and is based on both total consumption and maximum load. Systematically reducing maximum load by shaving off load peaks thus leads to savings in the capacity price.

Additionally, in some countries, consumers are rewarded with a substantially lower capacity price for what is called “atypical grid usage”, meaning that their period of highest demand falls into the off-peak hours. With this incentive, DSOs aim to level the general gap between times of high and low demand.

How does it work in practice?

Peak load shaving is already quite a common method to reduce individual energy costs. No additional agreement is needed with the electricity supplier or the DSO, if costs are based on automatic measurements. Technical requirement is an automatic load management system that switches off certain electrical devices for a limited time if a maximum load level is reached. It is determined beforehand via a priority list which devices will subsequently be switched off. Herein, requirements of the specific activities in the property (e.g. production processes) have to be observed in order to prevent any negative influence.

For atypical grid usage, where applicable, technical requirements are similar. On the administrative side, the discount for atypical grid usage has to be solicited at the DSO.
If own generation capacity is present, the objective of the VPP is to balance out the consumption and decentralized generation in order to lower the net peak offtake/injection. In the case of flexible generation capacity (e.g. a CHP plant), it can be used actively to compensate load peaks, and/or to contribute to atypical grid usage by producing mainly during peak hours.

Who can benefit, and what are costs and risks?

Any consumer who pays for grid usage based on its actual measured load profile (e.g. in Germany: consumers with an electricity consumption over >100.000 KWh per year) can reduce their costs by flattening the peak demand. It is especially attractive for consumers whose load profile shows high but short-timed peaks. If several high-capacity devices are present, alternating instead of parallel operation may be a good opportunity to flatten the peak demand.

Achieving atypical grid usage typically requires a greater flexibility in both total shiftable load and time. It is less viable for properties that follow the usual business-day schedule, e.g. ventilation and cooling in office buildings.

Necessary investments for the energy management system are moderate. Risks are low, as possible savings can be accurately determined beforehand, based on current grid usage costs.

Depending on the peak shaving potential and the grid usage fees in the respective country, savings can be minute to moderate.

If discounts for atypical grid utilization apply and the requirements are met, savings can be quite notable. In a case study on cold storage houses in Germany, savings on total energy costs in the magnitude of 5-10% were calculated[1].

2.1.2 Profit from flexible energy tariffs

What does it mean?

This business case targets the commodity price element of energy costs, i.e. the price per KWh consumed in a certain period. In several countries, time-dependent energy tariffs are already being offered for business consumers. This means that prices per kWh vary depending on the time of the day – the simplest tariff model differentiates between peak hours (e.g. 07:00 – 22.00) and off-peak hours (e.g. 22:00 – 07:00), but more complex tariff structures may be available. In order to reduce energy costs, flexible loads are shifted to off-peak periods.

Similarly, in some countries time-dependent tariffs for the feed-in of own production are common.

How does it work in practice?

The objective is to maximize consumption of energy at off-peak periods and minimize it at peak periods. If low and high tariff periods are predefined, planning can be done well in advance. In that case, technical requirements are similar to the reduction of grid usage costs. In the case of more flexible tariffs that change on short notice based on the actual grid situation, a more advanced communication infrastructure is needed. Here, the energy supplier sends a price signal, whereupon an intelligent local algorithm decides on the operation of devices.

Who can benefit, and what are costs and risks?

Consumers can profit if their energy contract includes a time-of-use commodity price. Also, larger consumers may be able to negotiate a time-of-use tariff with their current or another energy provider.

Regarding the required flexibility, even limited flexibility can be converted into savings. For example, if loads that normally occur towards the end of the peak period (e.g. during the late afternoon) could be postponed for a few hours, they would fall into the cheaper night/off-peak tariff hours. For large-scale consumers/producers however, it may be more attractive to procure electricity directly from

In the case of flexible local production capacities, these can be used to reduce grid offtake during peak hours.

If a **time-dependant feed-in contract for local renewable generation** is in place, this parameter has to be included in the operation planning of the smart energy network.
In times of high own production and high prices, it is optimal to lower own consumption and feed electricity to the grid, whereas during high production and low prices, own consumption should be increased.

[1] Gottschick and Ackmann, 2011:
Analyse des Lastverschiebepotenzials der Tiefkühllager im Hamburger Hafen; p.17
Available at http://eharbours.eu/showcases/showcase-hamburg

The return of investment can be calculated quite easily based on the amount of shiftable load and the spread between peak and off-peak price. These parameters, however, may vary largely between businesses and the energy contract, respectively. Risks are very limited if load shifting is planned carefully.

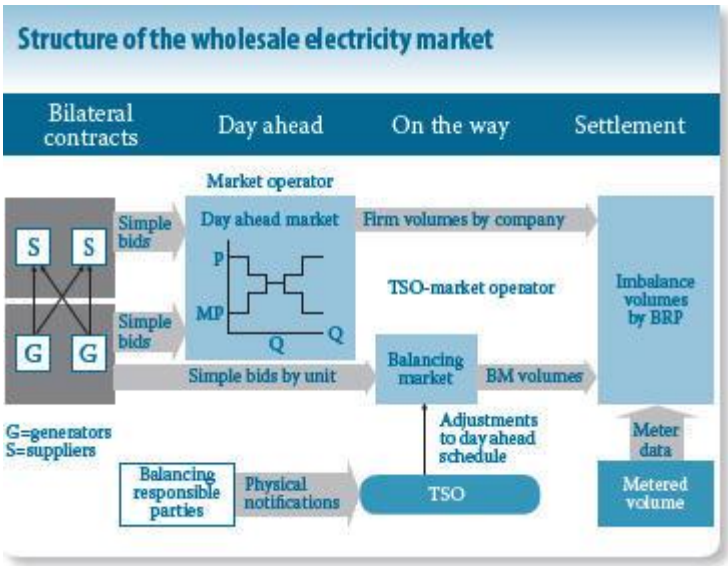
2.2 Trade on the wholesale market

What does it mean?

Energy exchange markets operate spot and derivatives market platforms for trading energy and energy-related products such as physical electricity, emissions and contracts on natural gas and coal.
Participants can use the different markets to buy and sell electricity on short and long terms. When intending to participate in the wholesale market, one is confronted with an entry barrier in terms of minimum volume/capacity. In particular, individual facilities (distributed generation) might be too small for market entrance. This is the reason why traders on the energy exchange market are mainly operators of power plants, utility companies or large scale consumers. However, the entry barrier can be overcome by joining different individual facilities together into a VPP which can trade on the energy market.

When considering the wholesale energy market one can make a distinction between bilateral contracts and the power exchanges. The bilateral contracts (over-the-counter trading) are customized contracts wherein the relevant tariff depends on the voltage level of the connection and often also on peak power. The power exchanges are markets where multilateral and anonymous contracts can be traded upon payment of an entrance and annual fee.

Figure 1: structure of the wholesale electricity market



Source: http://rbd.doingbusiness.ro

On the power exchanges, participants can trade on the short run via the spot markets or on the long run via the futures markets. On the short term spot market, the Day-ahead market (DAM) provides standardized products (hourly or multi hourly) to sell and purchase electricity to be delivered the day after. The Intraday Market (IM) provides standardized products (hourly and multi hourly) to sell and purchase electricity intraday until shortly before delivery to adjust the position between day-ahead predictions and time of the delivery. On the long run future markets, contracts for baseload power (0-24h) are traded for a contracted period of a month, quarter, year or multiple years.

The European Energy Exchange (EEX / EPEX Spot) is operating spot markets for Germany, Austria, Switzerland and France. APX-ENDEX operates spot and futures markets for electricity and natural gas in the Netherlands, the United Kingdom and Belgium (for full reference on national spot markets, see chapter 3).

Given a shiftable energy demand or a flexible electricity production (e.g. CHP), short term markets can be used to to minimize the costs for the energy needed or to optimize the revenues from own generation.

How does it work in practice?

The trading at a stock exchange market makes it mandatory to take up the role of a BRP. A BRP consolidates suppliers and consumers into a virtual group, within which the supply and demand have to be balanced. A company or a network of consumers and producers that wants to market flexible loads needs to have an authorized dealer or an external broker for the trading at the stock exchange. In addition to this a communication infrastructure has to be build up to for monitoring and to get control over the electrical devices.

A large scale electricity consumer/producer with certain flexibility or a VPP can trade amounts of energy on the spot market. If the difference between a pre-arranged price and the current spot market price is higher than the added value the consumer can sell a part of the purchased energy. Another option at a high price phase would be to pre-draw the electricity demand or to shift it to later hours. This is a so-called swap trade. An electricity producer with flexibility in the choice of his operating hours can benefit from the daily peak price by shifting the production into times of high prices.

Who can benefit, and what are costs and risks?

Regarding the eligibility requirements, the direct marketing/purchase of energy amounts is especially attractive for large scale industrial consumers and producers. Another option would be to pool a number of smaller consumers and producers into a VPP to reduce trading costs. This option can even become a necessity given the fact that some energy markets require a minimum volume/capacity.

Besides the general market price risks, companies that market flexible loads have to ensure that the operational processes won’t get disrupted.

Participation in the energy wholesale markets is typically associated with entrance fees and annual subscription fees. These fixed charges can become of considerable size. Furthermore a supplement has to be paid for each volume of energy traded.

The financial benefits depend on the structure of the stock market prices and an alternative conventional full supply contract as well as the flexibility in the electricity demand or production. For a production unit like an CHP or an wind turbine the extra benefit would depend on a potential feed-in tariff in combination with the direct marketing.

An addidional advantage of the self-service procurement would be the improved transparancy of energy prices. In a fast changing liberalised market with an increasing need for flexible demand and production the insight into the structure of the market is of great value.

2.3 Balancing group settlement

What does it mean?

The principal function of the balancing responsible party (BRP) is to assist the TSO in balancing supply and demand close to or during time of delivery. The BRP pools producers and consumers into a clearing group. BRPs are the basic structure for the clearing of the electricity supply. Every utility or electricity producer/consumer, who sells or buys energy on a market or acts as an energy supplier, has to rely on a BRP.

As the role of the BRP is to manage imbalances within the balancing group it is responsible for, it has an interest to exploit existing flexibilities within the balancing group for mitigating imbalances.

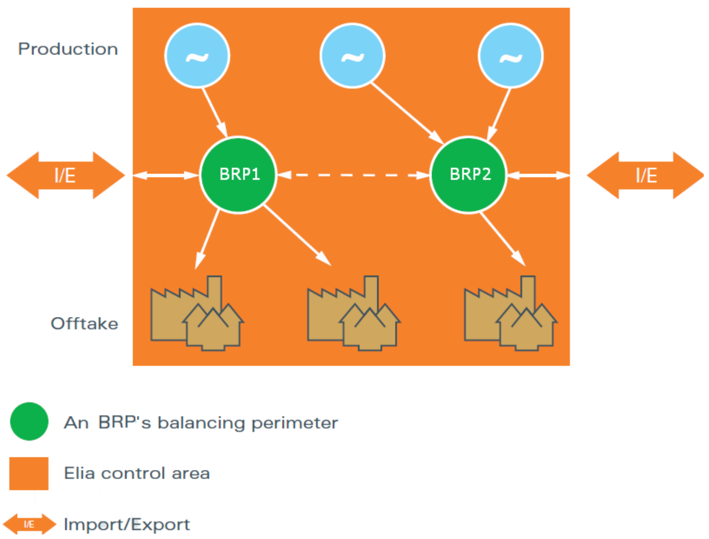
The BRP is in charge of making a day-ahead forecast for the demand of his pool and buying the amount of energy needed on the energy exchange market or directly from a producer (OTC). During a given day, every BRP has deviations of the actual energy demand from the day-ahead forecast. Due to these deviations, balancing energy has to be used by the TSO to stabilize net frequency at 50Hz. In the so-called clearing process, the BRP has to pay for the use of balancing energy due to the deviations of its balancing group.

The method by which the fees for the occurred deviations are calculated varies from country to country. In Germany, for example, fees are based on the amount and price of the balancing energy actually used at the time of the deviation.

Also, there are situations where the deviation of a BRP's portfolio can even result in earnings: If the deviation of a BRP portfolio is in the opposite direction of the deviation of the whole system at that time, this deviation would actually reduce the need for balancing energy and thus "help" the system as a whole. However, this is not necessarily the case in all NSR countries.

By controlling and shifting the energy demand in order to reduce the deviation from the day-ahead forecast, the cost for BRP imbalances can be reduced: The internal load balancing replaces the paid balance energy. In turn, the BRP may reward those consumers/producers that offer flexibility and contribute to a better reliability of their balancing group.

Figure 2: the balance mechanism



Source: http://www.elia.be/en/products-and-services/product-sheets#balance

How does it work in practice?

The BRP will request flexibility from its clearing pool to avoid paying imbalance costs to the TSO
The BRP needs to be able to have control over the switchable loads, or to influence the loads via a price signal. Furthermore a monitoring system is needed to get information about the current total load within the portfolio of the BRP.

Where applicable, the business case can be extended to actively assisting the TSO in balancing the transmission system, resulting in revenues for the BRP. For this, the BRP has to get information from the TSO about the current direction of the deviation in the transmission system. When the system needs downward regulation (system is long), the BRP will cause its customers to consume more/produce less, and vice versa if the system is "short".

Who can benefit, and what are costs and risks?

Every consumer that has a potential to reduce, increase or to shift his electricity demand can contribute to reduce the need for balancing energy in the portfolio of its BRP. Similarly, producers with flexible generation capacity can take part by controlling their production output.
Smaller consumers within a facility can be integrated via a local load management system.

The risks for this marketing option are low. As with all demand side regulation measures, it must be ensured that processes are kept unaffected. As mentioned above, in some countries a deviation of a BRP can even result in financial benefits, depending on the status of the whole electricity grid. In such cases, a more intelligent dispatching mechanism is needed that takes into account the current grid situation.

The obtainable revenues for this business case are determined by the avoided costs for balancing group imbalances. For a first assessment, a historic load profile is analyzed together with the deviation costs that occured in the same period. Given the available flexibility, it can be roughly estimated what share of the deviations (and costs thereof) could have been avoided through active balancing group settlement.

2.4 Offer reserve capacity

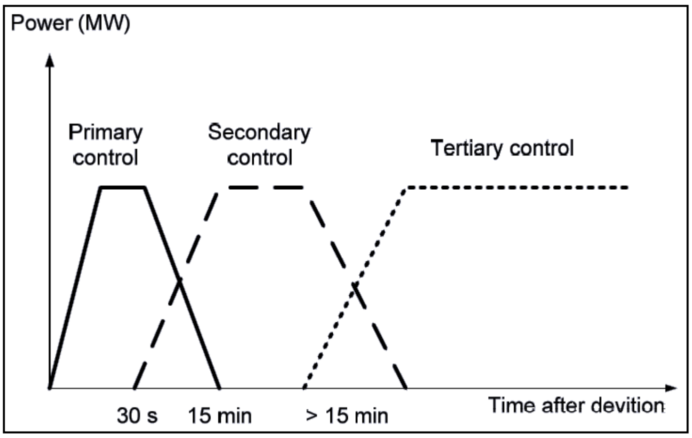
What does it mean?

Reserve capacity is needed to stabilize the grid frequency at 50Hz. Frequency fluctuations are tolerated in a very narrow range of +/- 0.02 Hz. Deviations directly reflect an imbalance of load and power generation: Having more generation than demand leads to frequencies over 50Hz, more demand than generation leads to frequencies below 50 Hz.

Reasons for frequency fluctuations are deviations from the day-ahead prognoses of generation and demand as well as drop-outs of larger loads or generation facilities. To be able to respond to imbalances, the TSOs are required to contract (in advance) certain amounts of reserve capacity, i.e. physical generation or consumption capacities. In order to compensate deviations in both directions, positive and negative reserve capacity is needed. **Positive reserve capacity** provides extra power to the grid in the form of additional generation or reduced consumption. **Negative reserve capacity,** in the form of reduced generation or additional consumption, is dispatched if power supply is too high.

The reserve capacity system is divided into three stages: Primary, secondary and tertiary control (see figure below).

Figure 3: Dispatch scheme of different reserve capacity types



Source: [Vuorinen, 2007]

Primary control is the first stage used to rule out system imbalances. The purpose of primary control is to respond immediately to load and consumption variations and to maintain the system frequency within specified limits. Primary reserve capacity is active most of the time, and has to react within 5-20 seconds if dispatched. Therefore, it is usually provided by power plants already running, which can modulate their output according to requirements.

Secondary control is dispatched after about 30 seconds to relieve the primary reserve in case of ongoing imbalances, and to normalize the system frequency after a deviation. Secondary reserve is also dispatched automatically by the TSO.

Tertiary control is the third stage of reserve capacity, which ensures that sufficient secondary control reserve is always available, and that such reserve is distributed appropriately among the available generators. It enters into action within 15 minutes of a disturbance, and is only active during some ¼-hour-periods of the day. In most countries, it is activated manually by the provider of tertiary control after notification from the TSO.

How does it work in practice?

In the countries of the North Sea Region open and transparent market platforms exist, where providers of reserve capacity can place contingents of positive and/or negative reserve capacity in (daily, weekly, monthly) auctions. Markets for reserve capacity are divided according to the three types of reserve capacity (primary, secondary, tertiary) and can have separate national rules and regulations for each type.

In order to participate in one of the reserve capacity markets, each facility has to pass a prequalification procedure: Herein, it is verified that the facility is capable of delivering the respective type of reserve capacity according to the rules and regulations of ENTSO-E (UCTE operations handbook Appendix 1) and national regulations. Important tests are whether the facility is able to deliver reserve capacity within the required time span after a dispatch and if it can be sustained without greater fluctuations for an extended time. The prequalification procedure is led by the locally responsible TSO.

The remuneration for the offering of reserve capacity is very country specific. In some countries there is a capacity price, for being ready to deliver regulating power with short notice (provision of reserves), and an energy price for regulating power that is actually delivered (activation of reserves). In other countries, inter alia the Netherlands and Denmark, only an activation price is offered.

Country-specific details for the different types of reserve capacity in the NSR countries are listed in chapter 0.

Who can benefit, and what are costs and risks?

In principle, anybody can profit who is able to provide:
a) Additional generation or reduced load in case of a low frequency (positive reserve capacity) and/or
b) Additional load or reduced generation in case of high frequency (negative reserve capacity).

However, providers have to follow the rules and regulations of the (national) control block and/or control area within the ENTSO-Es synchronous area. Here, strict requirements for each type of reserve capacity are stated.

In practice, providing primary control is virtually impossible for decentralized producers/consumers due to the very short reaction time and the virtually continuous dispatch. Offering secondary reserve is more feasible, although technical requirements may still be too strict for some facilities. The most accessible option is to offer tertiary reserve, as activation times are also long enough to cold-start a CHP plant, for example.

Yet, also in the case of tertiary control, flexibility regarding shiftable load and time has to be quite big – in all reserve capacity markets, minimum block sizes for reserve capacity offers exist. If contracted, the respective load block has to be held available constantly throughout the contract window. If the facility is dispatched and fails to actually deliver reserve power, substantial penalties may apply. As another consequence, being contracted to provide reserve capacity greatly limits the possibilities to serve other business cases in the meantime.

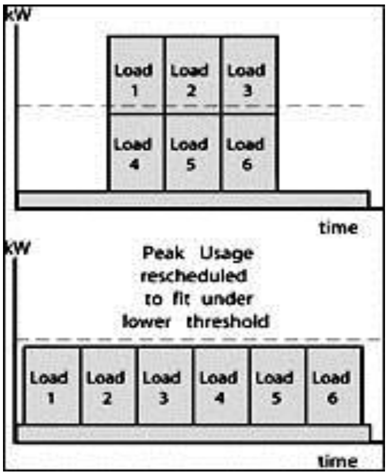
Another obstacle for interested parties is the volatile and not very predictable development of reserve capacity prices that make investments with a long return period rather risky at the moment.
In addition, prequalification procedures and other formal requirements tend to be rather complex and cost-intensive.
In order to allow smaller producers or consumers to access the reserve capacity markets, in many countries specialized companies are putting together **reserve capacity pools**. They offer to exploit smaller flexibility potentials on a contract base, take care of the prequalification, the technical implementation and the market placement, and keep part of the earnings in exchange. This can be a convenient and less risky option for smaller facilities.

Earnings for the provision of reserve capacity can be very attractive. The highest revenues are usually achievable for primary control, somewhat less for secondary control and still less for tertiary control. Also, earnings can be quite different for negative or positive reserve capacity. Chapter 0 provides a basic overview of potential earnings in the different NSR countries. Again, pool operators may provide more reliable gratification models.

2.5 Local system management

Loads and distributed generation impose a certain burden on the local grid. Depending on the evolution of the (net) injection/offtake pattern, network investments are or will be needed. In this context, flexibility allows businesses to minimize their demand peaks and/or regulate power usage across their entire enterprise to cope with local grid constraints.

Figure 4: load rescheduling



Source: [IEN, 2011]

The operation of a VPP in a way that is taking the local grid constraints into account is especially interesting for the DSO. Via local system management the DSO can defer investments in reinforcement of the distribution grid. In fact there is a general benefit in the form of a shift in system peak demand and it helps solving specific local network congestion issues.

In terms of benefits for the operator of the VPP it can be stated that when flexibility is used to lower the total peak demand, the operator immediately benefits through a lower electricity bill when a peak-demand component is integrated in the electricity contract. Furthermore, flexible time-based tariffs may be available through the DSO that generation and grid constraints into consideration. These may be communicated either via price signals, also known as indirect control (e.g. TOU) or via control signals (automated active demand), and allow the use of intelligent cost-optimization algorithms for the VPP operator.

Thus, the benefits for the VPP operator in this business case can be twofold:

- Lower electricity bill if a peak component is integrated in the electricity contract (also described in section 2.1.1)
- Remuneration offered by DSO for rescheduled load for local system management purposes (for the moment, no existing tariff structures are known)

2.6 Offer further grid stabilization services

The business options stated here only apply for large-scale producers/consumers connected to the high voltage grid, and are therefore not described in detail.

2.6.1 Providing reactive power

Reactive power, just as real power, must be balanced throughout the power system. Failure to do so can result in voltage collapse and cascading blackouts. Voltage problems can occur on transmission level but also on local level due to the presence of distributed generation.

Static reactive power support is provided by capacitors embedded throughout the grid, while dynamic reactive support must come from generators, synchronous condensers or dynamic transmission devices. To date there have not been any loads that are capable of supplying dynamic reactive reserves to the power system. Reactive supply is typically not procured through competitive markets.

Reactive power is usually provided by large central power plants on request of the TSO. Flexibility offered by a VPP may locally contribute to voltage control but the development of adapted strategies might be needed.

2.6.2 Congestion management

Congestions in electric power systems occur by overstressing grid operating facilities (e.g. conductions, transformers).
For prevention TSO's trade physical transmission capacities. After completing trading and taking into account load schedules, power plant operating plans and wind feed-in forecasts, the TSO checks whether available transmission capacities are sufficient.

Otherwise, the TSO has to initiate additional measures in order to control voltage and frequency level. Besides procurement of reserve capacity (see chapter **Fehler! Verweisquelle konnte nicht gefunden werden.**), redispatch and countertrading, TSO`s are able to negotiate contracts with significant electricity consumers to be able to switch them off when grid load exceeds limit.

Usually, load switch-offs are individually contracted between TSO and facility operators. Due to the large magnitude of loads required to stabilize the transmission system, this option is most viable for large-scale consumers.

3 Situation in NSR countries

3.1 Germany

3.1.1 Regulations regarding universal business cases:

<table>
<tr><th colspan="2">1. Contract optimization</th></tr>
<tr><td>Layout</td><td>Contractual agreements between electricity provider/DSO and consumer.</td></tr>
<tr><td>Requirements for participation</td><td>Reduction of grid usage fees: For all customers with electricity consumption > 100.000 kWh per year; automatic measurement/billing, no solicitation necessary
“Atypical grid usage”: Possibility to get a discount if times of highest grid usage are outside of peak periods defined by the DSO. Discount has to be solicited at the DSO.
Flexible energy tariff: Simple peak/off-peak tariff model generally available to commercial customers. Large-scale customers may be able to negotiate individual prices based on their load profile.</td></tr>
<tr><td>Costs, risks & benefits</td><td>Costs: Basic local load management system required, no administrative costs
Risks: None
Savings:
Moderate savings on grid usage fees for peak load reduction depending on load profile
Potentially higher savings if “atypical grid usage” can be reached
Flexible energy tariffs: For small and medium business consumers, off-peak prices are around 20% lower than peak prices. Saving potential depends on total shiftable load</td></tr>
<tr><td>Development & outlook</td><td>Trend: In the mid-term future, development may go towards more flexible time-of-use energy tariffs</td></tr>
<tr><td></td><td>www.effiziente-energiesysteme.de/themen/lastmanagement/spitzenlastreduktion.html
www.50hertz.com/de/129.htm</td></tr>
</table>

<table>
<tr><th colspan="2">2. Trade on the wholesale market</th></tr>
<tr><td>Layout</td><td>European Energy Exchange (EEX / EPEX Spot) for Germany and Austria. Relevant markets: Day-ahead and intraday trading / swap</td></tr>
<tr><td>Requirements for participation</td><td>Buyers and sellers of energetic products (own account, customer contracts, brokering): Necessary professional qualifications for trading, minimum equity, ICT infrastructure.
Smallest tradable amount: Hourly block of 100 kWh</td></tr>
<tr><td>Costs, risks & benefits</td><td>Costs: transaction costs 0.125 – 0.750Cent per MWh; yearly trading fee of 25.000 €; ICT connection up to 40.000 €/y
Risks: Cost savings depend on market prices which are difficult to predict, Infrastructure investment may not be recovered
Benefits: Savings compared to full-service contract depend on current energy tariff. Savings by load shifting compared to unstructured procurement on the market depend mainly on the spread between base and peak prices. Exemplary savings in 2010 for 1 MW of shiftable load:
<table>
<tr><th>Shift from</th><th>Saving per MW</th><th>Assumptions</th></tr>
<tr><td>11 am -> 3 pm</td><td>27 €/day</td><td rowspan="3">EEX average prices 2010</td></tr>
<tr><td>11 am -> 7 am</td><td>9 €/day</td></tr>
<tr><td>6 pm -> 10 pm</td><td>8 €/day</td></tr>
</table>
Based on Gobmaier, 2011: Markets for Demand Side Management
http://www.ffe.de/download/article/395/20120216_Markets_for_DSM.pdf</td></tr>
<tr><td>Development & outlook</td><td>Average peak and off-peak prices in 2011: [Graph]
Trend: New services: “Energy Brokers” for smaller electricity consumers</td></tr>
<tr><td>Further information</td><td>www.next-kraftwerke.de/wissen/direktvermarktung
www.energylink.de/strombeschaffung.html
www.energylink.de/stromvermarktung.html</td></tr>
</table>

<table>
<tr><th colspan="2">3. Balancing group settlement</th></tr>
<tr><td>Layout</td><td>BRP is responsible for balancing group deviations towards TSO.</td></tr>
<tr><td>Requirements for participation</td><td>Load control system, balance group monitoring and forecast system are necessary. In order to maximize savings, information on current grid situation is needed (see “risks” below).</td></tr>
<tr><td>Costs, risks & benefits</td><td>Costs: Load management infrastructure and planning/forecast system
Risks: Fees for schedule deviations are not transparent and depend on the price for balancing energy at the respective moment. BRPs can even get paid for deviations that actually “help” the grid in that moment. German system also includes the possibility for BRPs to clear deviations via a “day-after-market”.
Benefits: Potential savings through balancing group settlement are hard to determine and depend on balancing energy prices. Current savings potential is low to moderate.</td></tr>
<tr><td>Development & outlook</td><td>Rising balancing energy prices could make this business case more attractive in the future.</td></tr>
<tr><td>Further information:</td><td>www.effiziente-energiesysteme.de/themen/lastmanagement/bilanzkreisungleichgewichte.html
www.next-kraftwerke.de/wissen/regelenergie/ausgleichsenergie</td></tr>
</table>

<table>
<tr><th colspan="2">4. Offer reserve capacity</th></tr>
<tr><td>Layout</td><td>Open auctioning platform www.regelleistung.net, following ENTSO-E regulations</td></tr>
<tr><td>Requirements for participation</td><td>General participations conditions: necessary information and communication infrastructure, organizational issues, pooling allowed.
<table>
<tr><th>Criteria</th><th>Primary Control</th><th>Secondary Control</th><th>Tertiary Control</th></tr>
<tr><td>Minimum offer size</td><td>1 MW</td><td>5 MW</td><td>5 MW</td></tr>
<tr><td>Activation within</td><td>30 s</td><td>5 min</td><td>15 min</td></tr>
<tr><td>Availability</td><td>15 min with 100% of offered capacity</td><td>15 min with 95% of offered capacity</td><td>15 min - 4 h with 100% offered capacity</td></tr>
<tr><td>Duration of call</td><td>1 week</td><td>12 to 60 h</td><td>4 h</td></tr>
<tr><td>Frequency of auctions</td><td>weekly</td><td>weekly</td><td>daily</td></tr>
<tr><td>Pooling options</td><td colspan="3">Pooling possible within the control area</td></tr>
</table>
Based on information available from www.regelleistung.net</td></tr>
<tr><td>Costs, risks & benefits</td><td>Costs: if necessary, installation costs for load control system and ICT
Risks: Failure to provide contracted balancing energy is sanctioned. Prices are volatile.
Benefits: Vary depending on type of reserve capacity
<table>
<tr><th>Type</th><th>Profit per MW</th><th>Assumptions</th></tr>
<tr><td>Primary control</td><td>560 €/day</td><td>Feb. – Aug. 2011</td></tr>
<tr><td>Secondary control</td><td>260 €/day</td><td>Average prices 2008-2010, without commodity price</td></tr>
<tr><td>Tertiary control</td><td>95 €/day</td><td>Average prices 2008-2010, without commodity price</td></tr>
</table>
Based on Gobmaier, 2011: Markets for Demand Side Management
http://www.ffe.de/download/article/395/20120216_Markets_for_DSM.pdf</td></tr>
<tr><td>Development & outlook</td><td>Price for positive tertiary reserve capacity has decreased substantially over the last years.
Trends: Shorter tendering periods, lower minimal offer sizes, reduced minimum availability. Development of prices is difficult to predict, but due to higher shares of intermittent renewable energies, the demand especially for negative reserve capacity is expected to rise in the near to mid-term future.</td></tr>
<tr><td>Further information</td><td>www.regelleistung.net
www.effiziente-energiesysteme.de/themen/lastmanagement/regelenergie.html
www.next-kraftwerke.de/wissen/regelenergie
http://terajoule.innovationsraum.de/fileadmin/templates/ces/pdf/Information_Virtuelles_Kraftwerk_Direktvermarktung_und_Regelenergie.pdf</td></tr>
</table>

<table>
<tr><th colspan="2">5. Offer grid stabilization services</th></tr>
<tr><td>Layout</td><td>Business-to-business contracts between TSOs and large scale producers/consumers</td></tr>
<tr><td>Requirements for participation</td><td>Reactive capacity is provided by power plants, contracted by the TSO. Contracts are negotiated individually
Load shedding is also agreed upon individually between TSOs and large scale consumers. The maximum period for each contract is 1 year, minimum switchable load is 50 MW.</td></tr>
<tr><td>Costs, risks & benefits</td><td>Costs: Load management system with ICT connection to TSO
Risks: In the case of load shedding contracts, production/operation at the consumer’s property</td></tr>
</table>

	may be affected. • Benefits: Load shedding contracts usually include a large capacity price component that the consumer receives regardless if switching actually occurs.
Development & outlook	In a 2012 draft of the Federal Energy Law (Energiewirtschaftsgesetz), it is planned to regulate the switching of large-scale consumers. A fixed capacity premium is established, depending on the total shiftable load: For loads <50 MW, 30 TEUR/MW are paid per year. For loads <100 MW, the premium is 45 TEUR/MW per year, and for loads <150 MW, 60 TEUR/MW per year. The law will be brought into the legislative process in the course of 2012 (see sources below).
Further information	http://www.effiziente-energiesysteme.de/themen/lastmanagement/netzstabilisierung.html http://www.ipp.mpg.de/ippcms/ep/ausgaben/ep201201/0112_lastmanagement.html

3.1.2 Additional business cases in Germany

I) Direct marketing of renewable energy production

In Germany, feed-in tariffs for accelerating the development of renewable energy technologies are in place. They are regulated in the Renewable Energies Law (*Erneuerbare-Energien-Gesetz*/EEG). They vary depending on the renewable source, size and location (see box). The subsidy costs are allocated through DSO, TSO and energy supply companies to end consumers (**Fehler! Verweisquelle konnte nicht gefunden werden.**).

German feed-in tariffs for renewables established by the Renewable Energies Law (EEG)

Table 1: Extract of feed in tariff for wind power plants according to EEG for 2012 in ct/kWh

	Basic remuneration	Increased initial remuneration (up to 5 years)	System service bonus (up to 5 years)	Small plants up to 50 kW
Wind power On-shore	4,87	8,93	0,48	8,93
Wind power Off-shore	3,5	15*	19	-

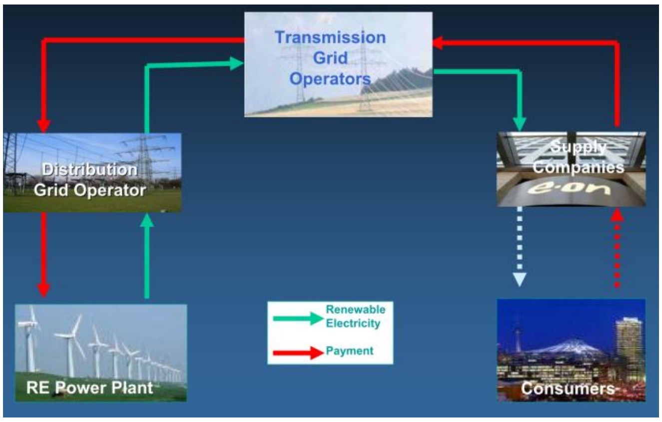
*** The higher initial remuneration for off-shore wind power plants is granted up to 12 years after implementing and is extended dependent on nautical miles and depth of water.**

Table 2: Feed-in tariff for PV plants according to EEG for 2012 in ct/kWh

Plant type	Remuneration
< 30 kW rooftop	24,4
> 30 kW < 100 kW rooftop	23,2
> 100 kW < 1.000 kW rooftop	22,0
> 1.000 kW rooftop	18,3
Ground mounted brownfields	18,8
Ground mounted Other	17,9

Source and information : http://www.erneuerbare-energien.de/files/pdfs/allgemein/application/pdf/eeg_2012_verguetungsdegression_bf.pdf

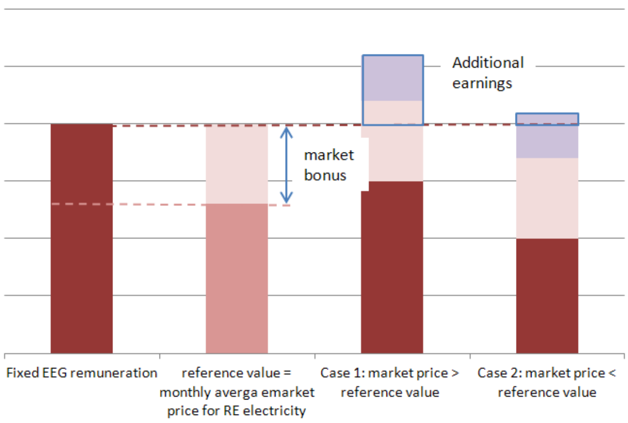
Figure 5: Transfer mechanism of the EEG allocation



In order to phase out subsidies in in the long term, the government aims to increase the direct selling of renewable electricity on the wholesale market. However, at the moment selling on the wholesale market is less profitable compared to the feed-in tariff for most renewable sources.
Therefore, three different tools are currently in place offering incentives for direct marketing of renewable energies:

- **"Market bonus model":** (*Marktprämienmodell*): It is available for operators of EEG-eligible plants that (partly or generally) sell their production on the wholesale electricity market. It covers the difference between the current average value on the electricity market and the EEG remuneration.
  If an operator decides to trade on the wholesale market, he also receives a management bonus meant to cover overhead costs (e.g. feed-in forecasts and trading efforts in order to reduce financial risks of inaccurate forecasts). For easily controllable generation capacities the bonus amounts to 0,3 ct/kWh, for those requiring complex forecasts 1,2 ct/kWh.
  Operators of EEG plants are able to choose every month between trade on the wholesale market or EEG remuneration.
  What makes this interesting for smart energy networks is that direct marketing of renewable production on the spot market, as described in chapter 2.2, becomes much more attractive. If production and feed-in are optimized to meet times of high spot market prices, benefits can be well above the EEG remuneration, depending on the energy source (see Figure 6).
  Further information:
  http://www.gdge.org/149.html
  http://www.next-kraftwerke.de/wissen/direktvermarktung/marktpraemie
  http://www.iwes.fraunhofer.de/content/dam/iwes/de/documents/Holzhammer_Uwe_Marktprämie%20und%20Flexibilitätsprämie.pdf

Figure 6: Market bonus model



Source: own elaboration

- **"Flexibility bonus"** (*Flexibilitätsprämie*): A further incentive was created especially for biogas plants selling their production on the wholesale market and therefore outside the EEG feed-in tariff: The aim here is to increase production capacities that support the grid by operating only in times of high demand/market prices: Operators that upgrade the capacity of their biogas plant receive a yearly capacity premium of currently approx. 130 EUR per additionally installed KW. To ensure that the additional capacity is actually used flexibly, the upgraded plant may not produce more power than the original one could have produced. Example: A 1 MW plant is upgraded to 1.5 MW. Monthly production may still not exceed 720 MWh (1 MW x 24h x 30 days). Similarly, newly installed biogas plants can receive the bonus; in this case the "flexible" share of production can be determined more freely.

In any case, the flexibility bonus is available for a maximum of 10 years, during which the plant has to **permanently** sell its entire production on the wholsesale market.
This makes an even stronger case for the implementation of a smart energy network when a biogas plant is present: A part of the production has to be marketed flexibly – together with the market bonus (see above), substantially higher profits compared to the EEG remuneration are possible, if production and own consumption are optimized according to the changing spot market and reserve capacity prices.
Further information: http://www.next-kraftwerke.de/wissen/direktvermarktung/flexibilitatspraemie
http://www.gdge.org/150.html

- **"Green electricity privilege"** (*Grünstromprivileg*): Energy supply companies whose end-consumer sales consist of >50% renewable energy (among which 20 % must be from fluctuating sources like PV and wind), have to pay a lower EEG allocation of 2 ct./kWh instead of currently 3.6 ct./kWh. The energy has to come from plants that are EEG-eligible, but sell their power directly outside the feed-in tariff.
  This is meant to increase the market demand for green electricity, and to give green energy suppliers a comparative advantage on the end consumer market.
  A smart energy network is not necessary for the direct marketing of renewable production. If renewable capacities are present in a smart energy network, however, this marketing option increases the number of options for selling renewable production.
  Further information: http://terajoule.innovationsraum.de/fileadmin/templates/ces/pdf/Information_Gruenstrom_Direktvermarktung.pdf

II) Optimize operation of CHP plants according to the "Combined Heat and Power Act" (*Kraft-Wärme-Kopplungs-Gesetz/*KWKG)

CHP plants are suited for a wide spectrum of applications where both heat and power are needed. Local CHP plants are well adjustable to current electricity demand. The integration of CHP plants is an important element for achieving flexibility in the electricity supply. As an incentive, the legislative authority implements the Combined Heat and Power Act (KWKG), regulating purchase and remuneration of combined electricity and heat generation by various technologies.

According to KWKG, grid operators have to connect CHP plants preferentially, there is also a feed-in priority for CHP power. The amount of CHP remuneration depends on year of installation and on installed capacity. Basically, total remuneration for CHP generated electricity is split in three components:

1. For each kWh of electricity produced, th operators receives a basic gratification between 5.11 ct/kWh for plants smaller than 50 kW and 1.5-2.1 ct/kWh for larger plants, independent of whether electricity is fed in or used by himself.
2. In case of feeding in of electricity, the operator gets a contractual agreed remuneration by the grid operator. If an agreement between the parties cannot be achieved, feed-in remuneration is set at the average spot market baseload price of the last quarter (currently 4-5 ct/kWh).
3. In addition, operator gets the avoided gird utilization costs of the upstream voltage level (about 0,2 – 1,5 Cent/kWh).

Based on which business case is used the total remuneration could be composed differently.

- Case 1: CHP generated electricity is sold to system operator. The CHP plant operator gets the basic gratification, a contractual agreed feed-in remuneration or average EEX baseload price and avoided grid utilization costs by the system operator.
- Case 2: CHP plant operator sells electricity to a third party for an agreed price and gets the basic CHP gratification from the grid operator. The system operator is committed to purchase and transmit the negotiated amount of electricity and in return gets grid utilization costs by the third party.
- Case 3: In case of partial own consumption, operator is able to reclaim electricity tax additional to the CHP gratification for this percentage, but in this case receiving feed-in remuneration or avoided grid utilization costs is not possible.

As part of a smart energy network, business cases can be combined optimally.
Further information:
http://asue.de/aktuelles---presse/kwk-gesetzaenderung-2012.html

3.2 Belgium

3.2.1 Manifestation of universal business cases:

<table>
<tr><th colspan="2">1. Contract optimization</th></tr>
<tr><td>Layout</td><td>Contractual agreements between electricity provider/DSO and consumer.</td></tr>
<tr><td>Requirements for participation</td><td>Electricity contract must contain at least two tariffs
Potentially other tariff structures (e.g. peak component) may be included in the electricity contract
Flexible electricity demand
Atypical load profile</td></tr>
<tr><td>Costs, risks & benefits</td><td>Costs: Basic local load management system required
Risks: none
Benefits:
Benefit from difference in peak and off-peak tariff. The average difference between peak and off peak load at the Belpex is about 28,15 €/MWh (2008).
Even greater savings are possible if more flexible energy tariffs are included in the electricity contract
Savings on the total peak load fee if a peak component is included in the contract and if the load profile allows peak shaving
Potentially greater savings if atypical grid usage can be reached
Savings on distribution and transmission tariffs (power subscription and additional power)
Benefits offered by DSO for peak shaving (load management in function of grid capacity)</td></tr>
<tr><td>Development & outlook</td><td>In the future it is expected that more flexible energy tariffs (e.g. TOU) will be designed.
Potentially DSOs will define remuneration structures for offering local load management services</td></tr>
<tr><td>Further information</td><td>n.a.</td></tr>
</table>

<table>
<tr><th colspan="2">2. Trade on the wholesale market</th></tr>
<tr><td>Layout</td><td>Trade on Belpex, power exchange for Belgium. Relevant markets: day-ahead and intraday trading</td></tr>
<tr><td>Requirements for participation</td><td>Minimum requirement on the volume traded is 0,1 MWh
Participation subjected to subscription
<table>
<tr><th></th><th>Minimum volume</th><th>Charges</th></tr>
<tr><td>Belpex</td><td>0,1 MWh</td><td>12.500 € (subscription)
25.000 €/y
0,14 €/MWh (transactions)</td></tr>
<tr><td>Endex</td><td>1 MW</td><td>10.000 €/y
0,02 €/MWh (transactions)</td></tr>
<tr><td>APX</td><td>0,1 MWh</td><td>5.000 € (subscription)
28.500 €/y
0,01 – 0,09 €/MWh</td></tr>
</table>
Source: VITO
In order to trade on the Belpex Spot Market, an applicant must:
Enter into a Participation Agreement CSS with the central counter party APX BV for the purpose of financial clearing and settlement of the contracts concluded on the Belpex market.
Enter into an Balancing Responsible Party contract (BRP contract) with Elia System Operator or designate a third party as BRP for the purpose of nominating the contracts concluded on the Belpex market to Elia System Operator.
Enter into an (Indirect) Participation Agreement with Belpex (and a Broker) for the purpose of trading electricity on the Belpex market via the Belpex trading platform.</td></tr>
</table>

<table>
<tr><td></td><td>This (Indirect) Participation Agreement includes both the Market Rules, as well as its implementing Market Procedures.
In case of an indirect participant, the indirect participant should enter into a bilateral agreement with its Broker for all practical arrangements regarding amongst others the submission of orders.</td></tr>
<tr><td>Costs, risks & benefits</td><td>Costs:
Subscription fee of 12.500 €
Annual membership fee of 25.000 €
Transaction cost of 0,14 €/MWh
Risks: Cost savings depend on market prices which are difficult to predict, Infrastructure investment may not be recovered
Benefits: Savings compared to full-service contract depend on current energy tariff. Savings by load shifting compared to unstructured procurement on the market depend mainly on the spread between base and peak prices.</td></tr>
<tr><td>Development & outlook</td><td>Future expectations are an advanced market coupling on day-ahead level as well as intraday level for the whole European region.</td></tr>
<tr><td>Further information</td><td>www.belpex.be</td></tr>
</table>

<table>
<tr><td colspan="2">3. Balancing group settlement</td></tr>
<tr><td>Layout</td><td>BRP is responsible for balancing group deviations towards TSO.</td></tr>
<tr><td>Requirements for participation</td><td>Load control system, balance group monitoring and forecast system are necessary. In order to maximize savings, information on current grid situation is needed (see “risks” below).</td></tr>
<tr><td>Costs, risks & benefits</td><td>Costs: Load management infrastructure and planning/forecast system
Benefits: Potential savings through balancing group settlement are hard to determine and depend on balancing energy prices. In Belgium the imbalance tariffs are based upon 1) the prices of activations requested by Elia to regulate the balance of its control area: the prices of upward regulation, taking into account the marginal incremental price (MIP), and the prices of downward regulation, taking into account the marginal decremental price (MDP); and 2) an additional price component (α, β) that encourages the BRPs to maintain their balance at a level close to zero regardless of the circumstances.
<table>
<tr><td colspan="2" rowspan="2"></td><td colspan="2">Situation in the Elia control area
Net Regulation Volume (NRV)</td></tr>
<tr><td>There is a surplus in the area
(offtakes < injections)
NRV is negative (net downward regulation)</td><td>There is a deficit in the area
(offtakes > injections)
NRV is positive (net upward regulation)</td></tr>
<tr><td rowspan="2">Imbalance in the ARP’s perimeter</td><td>Positive</td><td>A
MDP - $\alpha 1$</td><td>B
MIP- $\beta 1$</td></tr>
<tr><td>Negative</td><td>C
MDP+ $\beta 2$</td><td>D
MIP + $\alpha 2$</td></tr>
</table>
Source: http://www.elia.be/en/products-and-services/product-sheets#balance

where:
$\beta 1$ (€/MWh) = 0
$\beta 2$ (€/MWh) = 0
if the absolute value of the system imbalance is less than or equal to 140 MW;
$\alpha 1$ (€/MWh)= 0
$\alpha 2$ (€/MWh)= 0
if the absolute value of the system imbalance is greater than 140 MW
$\alpha 1$ (€/MWh)= average {(System imbalance QH-7)², …, (System imbalance QH)²} /15.000
$\alpha 2$ (€/MWh)= average {(System imbalance QH-7)², …, (System imbalance QH)²} /15.000.</td></tr>
<tr><td>Development & outlook</td><td>Rising balancing energy prices could make this business case more attractive in the future.</td></tr>
<tr><td>Further information:</td><td>http://www.elia.be/en/products-and-services/product-sheets#balance</td></tr>
</table>

<table>
<tr><th colspan="2">4. Offer reserve capacity</th></tr>
<tr><td>Layout</td><td>Offer flexibility to TSO for balancing purposes</td></tr>
<tr><td>Requirements for participation</td><td>
<table>
<tr><th>Criteria</th><th>Primary Control</th><th>Secondary Control</th><th>Tertiary Control</th></tr>
<tr><td>Total volume</td><td>100 MW</td><td>140 MW</td><td>400 MW</td></tr>
<tr><td>Min. offered size</td><td>-</td><td>5 MW</td><td>-</td></tr>
<tr><td>Reaction time</td><td>0 - 30 s</td><td>30 sec - 15 min</td><td>15 min – 8 hours</td></tr>
<tr><td>Availability</td><td>15 min with 100% of offered capacity</td><td>At least 15 consecutive minutes</td><td>Until problem is solved</td></tr>
<tr><td>Activation</td><td>Automatical</td><td>Automatical</td><td>Manually upon request from Elia</td></tr>
</table>
Source: VITO

Primary reserve is a service that can be provided by any UCTE grid user, as long as its facilities have the following technical characteristics:

They are fitted with an automatic speed, rotation and frequency control system. This equipment enables the production units or industrial processes to detect frequency variations in the grid automatically and react to them by activating their primary reserve
They have a system that is able to read the grid’s frequency
They are able to provide half of the contractual primary reserve within 15 seconds. The whole of the primary reserve must be deployed after 30 seconds and stay activated for at least 15 consecutive minutes.
They are available round the clock.

Only grid users that have already signed a CIPU[2] contract with Elia can sign a primary, secondary or tertiary reserve contract.

</td></tr>
<tr><td>Costs & benefits</td><td>

Costs: interface with the TSO must be installed and if necessary, installation costs for load control system and ICT
Risks: Failure to provide contracted balancing energy is sanctioned.
Benefits:

Primary reserves: Elia offers a set payment to grid users that provide primary reserve. The payment covers the costs involved in both providing and activating the primary reserve (no seperate payment for providing the reserve and activating the reserve).
Secondary reserve: a grid user receives payment for the provision of the reserve and for the activation of the reserve
Tertiary production reserve: a grid user receives payment for the provision of the reserve and for the activation of the reserve (there are far fewer requests to activate the tertiary reserve than to activate the primary and secondary reserves)

Tertiary frequency control:
<table>
<tr><th></th><th>2006</th><th>2007</th><th>2008</th><th>2009</th></tr>
<tr><td>Number of activations</td><td>2</td><td>0</td><td>5</td><td>11</td></tr>
<tr><td>Activated volume (MWh)</td><td>57</td><td>0</td><td>1007</td><td>1386</td></tr>
<tr><td>Average price of activation (€/MWh)</td><td>181</td><td>0</td><td>137</td><td>125</td></tr>
</table>
Source: http://www.elia.be/en/suppliers/purchasing-categories/energy-purchases#anchor1
</td></tr>
<tr><td>Development & outlook</td><td>Development of prices is difficult to predict, but due to higher shares of intermittent renewable energies. Potentially smaller production units (even if they are connected to the distribution grid) and other industries will be called upon to deliver the required reserves in the future. This may lead to an expansion of the total offered reserve capacity and the effect on the relevant payments are uncertain.</td></tr>
<tr><td>Further information</td><td>http://www.elia.be/en/products-and-services/product-sheets</td></tr>
</table>

5. Local grid constraints	
Layout	Flexibility allows businesses to minimize their demand peaks and/or regulate power usage across their entire enterprise in function of local grid constraints.
Requirements for participation	• Flexible electricity demand • Atypical load profile

Costs, risks & benefits	• Costs: interface with Elia, load management system, ICT costs
	• Risks: none
	• Benefits: benefits for the VPP operator in this business case can be dual:
	  ○ Lower electricity bill if a peak component is integrated in the electricity contract (see also contract optimization)
	  ○ Remuneration offered by DSO for reschedule load for local system management purposes (for the moment, no existing tariff structures are known)

Development & outlook	In the future it is possible, as when different price signals, also known as indirect control (e.g. TOU) or control signals (automated active demand) can be communicated in order to allow intelligent charging algorithms to take generation and grid constraints into consideration, the VPP operator benefits from price opportunities offered by the DSO.
Further information	n.a.

6. Offer grid stabilization services	
Layout	Business-to-business contracts between TSOs and large scale producers/consumers
Requirements for participation	• The federal Grid codes stipulate that any production unit with a nominal capacity of 25 MW or more is a regulating unit. • Voltage control services are governed by contracts of at least one year signed by Elia and the producer • Elia contracts some 2,700 MVAr of generation capacity and 100 MVAr of absorption capacity.

Costs, risks & benefits	• Costs: interface with Elia, load management system, ICT costs
	• Risks: In the case of load shedding contracts, production/operation at the consumer's property may be affected
	• Benefits:
	  ○ The service of supplying reactive energy is governed by a voltage control contract between Elia and the producer concerned.
	  ○ Elia pays the producers for the reserved control bands based on:
	    ▪ A unit price
	    ▪ The volume contracted in Mvar
	    ▪ The lenght of use

Further information	http://www.elia.be/en/products-and-services/product-sheets

[2] The BRPs, who are responsible for the injection of production units whose operation have an influence on the high-voltage system, are legally bound to conclude a contract with Elia for the coordination of the injection of the production units, commonly known as the CIPU (Coordination of the Injection of the Production Units) contract.

3.3 The Netherlands

3.3.1 Manifestation of universal business cases:

<table>
<tr><th colspan="2">1. Contract optimization</th></tr>
<tr><td>Layout</td><td>Contractual agreements between electricity provider/DSO and consumer.</td></tr>
<tr><td>Requirements for participation</td><td>Electricity contract must contain at least two tariffs
Potentially other tariff structures (e.g. peak component) may be included in the electricity contract
Flexible electricity demand
Atypical load profile</td></tr>
<tr><td>Costs, risks & benefits</td><td>Costs: Basic local load management system required
Risks: none
Benefits:
Benefit from difference in peak and off-peak tariff: When looking at the APX prices in energy reports, the gap between peak and off peak seems to be about 50 €/MWh (2008).
Even greater savings are possible if more flexible energy tariffs are included in the electricity contract
Savings on the total peak load fee if a peak component is included in the contract and if the load profile allows peak shaving
Potentially greater savings if atypical grid usage can be reached
Savings on distribution and transmission tariffs (power subscription and additional power)
Benefits offered by DSO for peak shaving (load management in function of grid capacity)</td></tr>
<tr><td>Development & outlook</td><td>In the future it is expected that more flexible energy tariffs (e.g. TOU) will be designed.
Potentially DSOs will define remuneration structures for offering local load management services</td></tr>
<tr><td>Further information</td><td>n.a.</td></tr>
</table>

<table>
<tr><th colspan="2">2. Trade on the wholesale market</th></tr>
<tr><td>Layout</td><td>Trade on APX, power exchange for the Netherlands. Relevant market segments are listed below:
<table>
<tr><th colspan="2">Market segments APX-ENDEX*</th></tr>
<tr><td>Spot Markets</td><td>Futures Markets</td></tr>
<tr><td>APX Gas NL
APX Gas UK
APX Gas ZEE
APX Power NL
APX Power UK
Belpex</td><td>ENDEX TTF Gas
ENDEX Power NL
ENDEX Power BE
ENDEX Power UK</td></tr>
</table>
Source: VITO</td></tr>
<tr><td>Requirements for participation</td><td>Enter into a BRP contract (in Dutch terms: program responsible) with TenneT or designate a third party as BRP for the purpose of nominating the contracts concluded on the APX market to TenneT.
Minimum requirement on the volume traded is 0,1 MWh
Participation subjected to subscription</td></tr>
</table>

	Minimum volume	Charges
Belpex	0,1 MWh	12.500 € (subscription) 25.000 €/y 0,14 €/MWh (transactions)
Endex	1 MW	10.000 €/y 0,02 €/MWh (transactions)
APX	0,1 MWh	5.000 € (subscription) 28.500 €/y 0,01 – 0,09 €/MWh

Source: VITO

Costs, risks & benefits	• Costs:
	  ○ Subscription fee of 5.000 €
	  ○ Annual membership fee of 28.500 €
	  ○ Transaction cost between 0,01 – 0,09 €/MWh
	• Risks: Cost savings depend on market prices which are difficult to predict, Infrastructure investment may not be recovered
	• Benefits: Savings compared to full-service contract depend on current energy tariff. Savings by load shifting compared to unstructured procurement on the market depend mainly on the spread between base and peak prices.

Development & outlook	Future expectations are an advanced market coupling on day-ahead level as well as intraday level for the whole European region.
Further information	www.apx.nl

3. Balancing group settlement	
Layout	BRP is responsible for balancing group deviations towards TSO.
Requirements for participation	Load control system, balance group monitoring and forecast system are necessary. In order to maximize savings, information on current grid situation is needed (see “risks” below).

Costs, risks & benefits	• Costs: Load management infrastructure and planning/forecast system
	• Benefits: Potential savings through balancing group settlement are hard to determine and depend on balancing energy prices. The Dutch imbalance tariffs are based on the market price for upward regulation and downward regulation, reserve and emergency capacity as offered by the producers, adjusted by an incentive component in order to stimulate BRPs to keep their balance.
	
	The following transactions are deemed to be effected between TenneT and BRP in imbalance:
	• Imbalance BRP surplus:
	  ○ BRP supplies the energy in imbalance to TenneT at imbalance price surplus,
	  ○ TenneT pays BRP (the imbalance price may have a negative value, in which case it will be BRP which pays TenneT).
	• Imbalance BRP shortfall:
	  ○ BRP sources energy in imbalance from TenneT at imbalance price shortfall,
	  ○ BRP pays TenneT (the imbalance price may have a negative value, in which case it will be TenneT which pays BRP).

Development & outlook	Rising balancing energy prices could make this business case more attractive in the future.
Further information:	http://www.tennet.org/english/operational_management/export_data.aspx?exporttype=Onbalansprijs

4. Offer reserve capacity	
Layout	Offer flexibility to TSO for balancing purposes
Requirements for participation	• Primary reserve system is obligatory for production units > 5MW • Market players (producers) who have production units of a certain minimum capacity (60 MW) are obliged by law to offer reserve capacity (secondary reserves) to the TSO by means of bids (a single buyer model). Production units of less than 60 MW can do this on voluntary basis.

Regulating capacity can be offered by contract or by the bid-system.

- Emergency capacity (=tertiary reserves) can only be contracted in advance by the TSO.

Costs & benefits

- Costs: interface with the TSO must be installed and if necessary, installation costs for load control system and ICT
- Risks: Failure to provide contracted balancing energy is sanctioned.
- Benefits:

Primary reserve system is obligatory for production units > 5MW. The maintenance of the primary reserve and the provision of the primary control contribution ***are not compensated for***.

Year	Share in UCTE production (%)	Minimum primary reserve (MW)
2010	3,9	116
2011	4,2	125

Source:
http://www.tennet.org/english/operational_management/system_data_preparation/primary_reserve.aspx

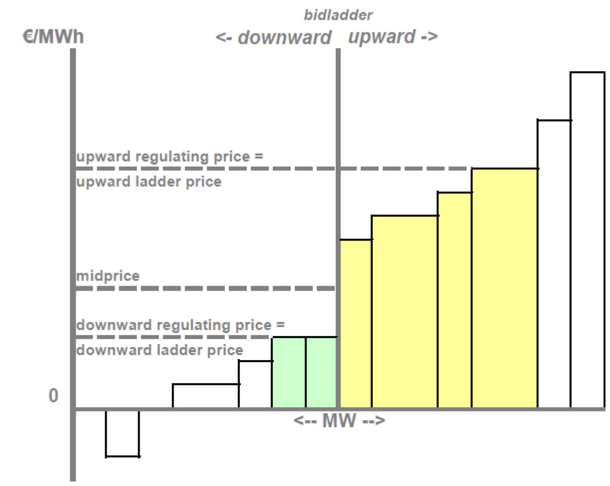
There is no obligation of plants to offer ***secondary reserve*** to the TSO. Secondary reserve is procured in two ways:

- Market maker contracts – By means of bilateral negotiations TenneT awards market maker contracts to suppliers. The contract obliges the supplier to always bid into the daily secondary reserve price ladder at an energy price he can choose within certain ranges (at maximum 1000 EUR above the dayahead price). He is remunerated for this market maker contract and – in case his bid gets called-off from the secondary reserve price ladder – he receives an additional energy payment. The contract therefore includes a capacity payment and an energy payment.
- Price ladder – In addition to market makers all technically qualified suppliers can bid into the price ladder at a certain energy price. They get remunerated if called corresponding to their bid price. They do not receive any capacity remuneration.

The selection of market maker contracts is not entirely transparent. TenneT awards annual contracts as a result of bilateral negotiations. Key decision driver will be the price to be paid for the obligation to bid into the price ladder. Secondary reserve energy is called following the bid price ladder, suppliers with lowest energy price are called first. Market makers receive their negotiated contract prices and - if called via the price ladder - their energy price bid.

There is no obligation to provide ***tertiary reserve*** to the TSO, TenneT. Producers or power consumers can offer this service if they fulfil the technical requirements (minimum bid sizes, ramping, availability, etc). Bidders need to bid into the daily price ladder announcing their ramping constraints and bidding in an energy payment.

The cheapest energy bid is called first. Tertiary reserve is called manually (via phone calls). Delivered reserve energy is remunerated at the bid energy price. Providers of downward reserve (who take electricity off the grid on short notice) pay to the TSO, providers of upward reserves receives the energy price for the delivered energy. There is no capacity payment for bidders.



	Source: http://www.tennet.org/english/tennet/publications/technical_publications/other_publications/onbalansprijssystematiek.aspx
	Development of prices is difficult to predict, but due to higher shares of intermittent renewable energies. Potentially smaller production units (even if they are connected to the distribution grid) and other industries will be called upon to deliver the required reserves in the future. This may lead to an expansion of the total offered reserve capacity and the effect on the relevant payments are uncertain.
Further information	http://www.tennet.org/english/operational_management/export_data.aspx?exporttype=Onbalansprijs http://www.tennet.org/english/operational_management/system_data_preparation/primary_reserve.aspx

5. Local grid constraints	
Layout	Flexibility allows businesses to minimize their demand peaks and/or regulate power usage across their entire enterprise in function of local grid constraints.
Requirements for participation	• Flexible electricity demand • Atypical load profile

Costs, risks & benefits	• Costs: interface with Elia, load management system, ICT costs
	• Risks: none
	• Benefits: benefits for the VPP operator in this business case can be dual:
	  ○ Lower electricity bill if a peak component is integrated in the electricity contract (see also contract optimization)
	  ○ Remuneration offered by DSO for reschedule load for local system management purposes (for the moment, no existing tariff structures are known)

Development & outlook	In the future it is possible, as when different price signals, also known as indirect control (e.g. TOU) or control signals (automated active demand) can be communicated in order to allow intelligent charging algorithms to take generation and grid constraints into consideration, the VPP operator benefits from price opportunities offered by the DSO.
Further information	n.a.

6. Offer grid stabilization services	
Layout	Business-to-business contracts between TSOs and large scale producers/consumers
Requirements for participation	Not known
Costs, risks & benefits	• Costs: interface with Elia, load management system, ICT costs • Risks: In the case of load shedding contracts, production/operation at the consumer's property may be affected • Benefits:
Further information	n.a.

3.4 UK

3.4.1 Manifestation of universal business cases:

1. Contract optimization	
Layout	Contractual agreements between electricity provider/DSO and consumer.

Requirements for participation	• Electricity contract must contain at least two tariffs µ
	  ○ Examples from UK:
	    ▪ **Economy 7 energy tariffs** (White Meter in Scotland) Offers *cheaper electricity at night* The '7' represents the seven hours of cheaper electricity available - usually between 1am and 8am, or midnight and 7am A double (day/night) meter is needed
	    ▪ **Economy 10 energy tariffs** Offers *cheaper electricity during certain off peak times* Economy 10 provides discounted prices for electricity used during ten off-peak hours er day (typically three hours in the afternoon, two in the evening and five overnight) Off-peak electricity costs can be half of peak prices, but many tariffs have an increased standing daily charge. A meter that displays separate readings for energy units used at different times of the day is needed. Not all energy suppliers offer Economy 10, and those that do may not offer the energy tariff to new customers.
	• Potentially other tariff structures (e.g. peak component) may be included in the electricity contract
	• Flexible electricity demand
	• Atypical load profile

Costs, risks & benefits	• Costs: Basic local load management system required
	• Risks: none
	• Benefits:
	  ○ Benefit from difference in peak and off-peak tariff
	  ○ Even greater savings are possible if more flexible energy tariffs are included in the electricity contract
	  ○ Savings on the total peak load fee if a peak component is included in the contract and if the load profile allows peak shaving
	  ○ Potentially greater savings if atypical grid usage can be reached
	  ○ Savings on distribution and transmission tariffs (power subscription and additional power)
	  ○ Benefits offered by DSO for peak shaving (load management in function of grid capacity)

Development & outlook	In the future it is expected that more flexible energy tariffs (e.g. TOU) will be designed. Potentially DSOs will define remuneration structures for offering local load management services
Further information	http://www.which.co.uk/switch/energy-advice/

2. Trade on the wholesale market	

Layout	Trade on market segments wholesale market:
	» Power exchanges
	  » Spot markets
	  » Future markets

Requirements for participation	• Auction Prompt market Spot market Third party Notification: Under the New Electricity Trading Arrangements (NETA), all trading parties have to report contracted positions to the Energy Contract Volume Aggregation Agent (ECVAA) The APX Power UK third party notification service allows members and non-trading members to easily submit contract notifications to ECVAA • Subscription obliged and subjected to an entrance fee
Costs, risks & benefits	• Costs: ***APX power UK*** Fee schedule

Entrance fee:	£5,000
Membership (per annum):	**Fee**
Full Membership	£25,750
View Only	£8,400
ECV Notification Service	£12,000
Clearing Membership*	£2,700
Technology*	£4,410

Source: [APX Endex web] *applied once per entity per year

Spot and Forward Power Markets Transaction Fees:		
Product	**Trading Fee (p/MWh)**	**Clearing Fee (p/MWh)**
≤ 2hrs Spot Power Continuous Orders or ≥ 4 hrs Spot Power Continuous Orders matched after 18:00 on D-1	4.75	0.5
≥ 4hrs Spot Power Continuous Orders matched before 18:00 on D-1	1.25	0.5
Trades via OTC give-up service	0	1.75
Day Ahead Auction	3.00	0.5
Pending ECV Notifications	1.5	0

Source: [APX Endex web]

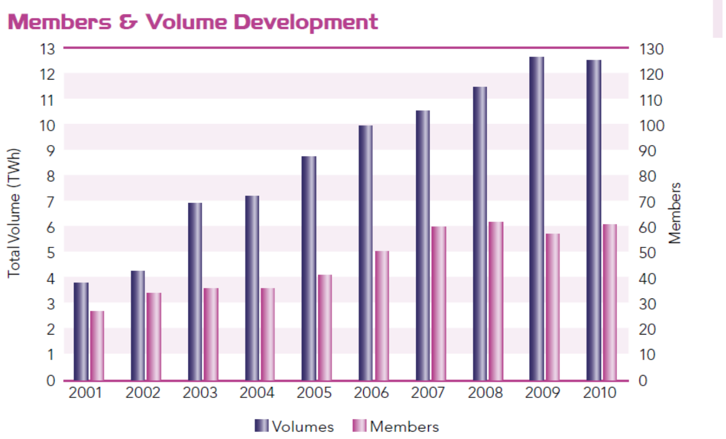
Endex power UK Fee schedule

Membership Fee	
ENDEX Power UK	€ 10,000
Combination of any 3 ENDEX markets	€ 40,000
All 4 ENDEX markets	€ 50,000
Variable Fee	
Transaction	£/MWh 0.005
Clearing Registration	£/MWh 0.005

Source: [APX Endex web]

- Risks: Cost savings depend on market prices which are difficult to predict, Infrastructure investment may not be recovered
- Benefits:

APX UK



Sources: [APX], [APX Endex web

APX Power UK – overview products:

The day-ahead auction is a market where power is traded for delivery the next day. The prompt market offers a series of standardized products available for continuous trading throughout the day. The spot market is a continuous market where adjustments to trades done in the day-ahead auction or prompt markets are made.

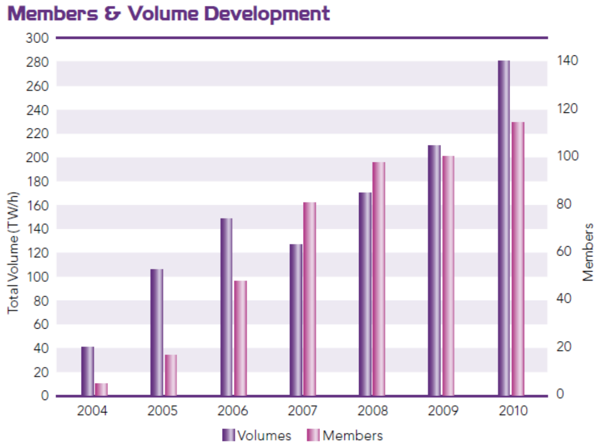
Product Snapshot

	Contract	Period Covered	Hrs	Opens for Trading
Prompt	Base week	23:00 Sun - 23:00 Sun	168	Rolling 4 weeks, open at any time
	Peak week	07:00 - 19:00 Mon - Fri	60	Rolling 4 weeks, open at any time
	Weekend base	23:00 Fri - 23:00 Sun	48	Rolling 2 weekends, open at any time
	Base	23:00 - 23:00	24	Rolling 7 days
	Peak	07:00 - 19:00	12	Rolling 7 days
	Extended peak	07:00 - 23:00	16	Rolling 7 days
	Off peak	23:00 - 07:00 + 19:00 - 23:00	12	Rolling 7 days
	Blocks 3 + 4	07:00 - 15:00	8	Rolling 7 days
	Overnight	23:00 - 07:00	8	Rolling 7 days
Spot	4 Hrs block	6 blocks/days, block 1 begins 23:00; block 6 ends 23:00	4	Rolling 7 days
	2 Hrs block	12 blocks/days, block 1A begins 23:00; block 6B ends 23:00	2	49 1/2 Hrs prior to start of delivery
Auction	1 Hr block	Day-Ahead Auction, 24Hrs/day, begins 23:00; ends 23:00	1	Hourly auction opens for order entry at 00:00, 14 days prior to delivery; matching takes place at 11:00 daily
	Half hour block	48 blocks/days, 1/2 Hr 1 begins 00:00; 1/2 Hr 48 to end 00:00	0.5	49 1/2 Hrs prior to start of delivery

Source: VITO

Endex Power UK

- Secure, transparent and anonymous exchange trading
- Central counterparty clearing
- OTC clearing service
- Cross-margining (between Dutch, Belgian, German, French power futures)



Sources: [APX], [APX Endex web]

N2EX UK power product areas

- The Spot Market – A continuous market for ½ hour contracts, 1 hour contracts, 2 hour blocks and 4 hour blocks, Overnight, Block 3+4, Peak, Off-peak, Extended Peak and Base.
- The Prompt Market – A prompt market for physically delivered power providing 4 hour blocks, Overnight, Block 3+4, Peak, Off-peak, Extended Peak and Base, Weekend and Weekly contracts for Peak and Base load. Identical contracts in the Prompt and Spot markets will be moved from the Prompt market to the Spot market at the close of the prompt market (19.00) on Fridays or two days prior to the beginning of the delivery period to avoid overlapping contracts.
- The Day Ahead Auction Market (DAM) - A day-ahead spot market auction for physically delivered power.
- The Future Market - The contract types are cash-settled pound sterling UK power futures listed for weeks, months, quarters and seasons (summer and winter).

Development & outlook	Future expectations are an advanced market coupling on day-ahead level as well as intraday level for the whole European region.
Further information	http://www.apxendex.com/index.php?id=234 http://www.apxendex.com/uploads/Corporate_Files/Annual_Reports/APX-ENDEX_Annual_Report_2010.pdf http://www.apxendex.com/uploads/Corporate_Files/Data_sheets/APX_Power_UK_data_sheet_2011.pdf http://www.nationalgrid.com/uk/Electricity/SYS/current

<table>
<tr><td colspan="2">3. Balancing group settlement</td></tr>
<tr><td>Layout</td><td>BRP is responsible for balancing group deviations towards TSO.</td></tr>
<tr><td>Requirements for participation</td><td>- Load control system, balance group monitoring and forecast system are necessary. In order to maximize savings, information on current grid situation is needed (see “risks” below).
- Participation in the balancing mechanism is optional and parties that choose to do so must submit bids and offers before Gate Closure to the system operator for each settlement period.</td></tr>
<tr><td>Costs, risks & benefits</td><td>• Costs: Load management infrastructure and planning/forecast system
• Benefits:
Each bid-offer pair includes:
• An Offer Price - the price a Party wants to be paid per MWh for an increase in generation or decrease in demand;
• A Bid Price - the price a Party wants to pay per MWh for a decrease in generation or an increase in demand (although it is possible to submit negatively priced Bids, i.e. a Party is paid to reduce generation);
• The Settlement Period for which the Bid/Offer applies;
• The upper and lower power levels between which the Bid/Offer applies

For each Settlement Period, the BSC Systems determine two distinct Energy Imbalance Prices
1. System Buy Price (SBP): If a Party has under-generated or over-consumed compared to their contracted volume, it will be charged for that that shortfall of energy at SBP
2. System Sell Price (SSP) : If a Party has over-generated or under-consumed compared to their contracted volume, it will have to sell that extra energy at SSP
There are two different methods for calculating the Energy Imbalance Prices:
1. Main pricing method: reflects the costs of balancing the Transmission System
2. Reverse pricing method: reflects the market price of electricity for that Settlement Period

Imbalance pricing:
<table>
<tr><th></th><th></th><th colspan="2">System imbalance</th></tr>
<tr><th></th><th></th><th>Long +</th><th>Short++</th></tr>
<tr><td>Party imbalance</td><td>Long</td><td>Paid SSP
(Main price)</td><td>Paid SSP
(Reverse price)</td></tr>
<tr><td></td><td>Short</td><td>Pay SBP
(Reverse price)</td><td>Pay SBP
(Main price)</td></tr>
</table>
Source: VITO
SSP = System Sell Price
SBP = System Buy Price
+ A 'long' system is one where there is more generation than demand
++ A 'short' System is one where there is more demand than generation

Main Energy Imbalance Price:
» The Main Energy Imbalance Price is calculated using the balancing actions that the SO accepted for that Settlement Period.
» The SO does not take all balancing actions for the same reason:
  » energy balancing actions are taken purely to balance the half hour energy imbalance of the transmission system.
  » system balancing actions are taken for non-energy, system management reasons
» A number of processes are used to minimize the price impact of system balancing actions :
  » Flagging – identifying balancing actions that are potentially system balancing. Once identified the Classification process will be used to decide if they are system or energy balancing;
  » Classification – assessing the Flagged balancing actions against the Unflagged balancing actions to determine whether they are energy balancing or system balancing. If a Flagged Action is more expensive than any Unflagged Action then we consider it to be a system balancing action and remove its price; and
  » Tagging – completely removing the price and volume of balancing actions so that</td></tr>
</table>

	no part is used in the final calculation. » After completing these processes the remaining balancing actions are **adjusted for Transmission Losses** and the **main Energy Imbalance Price is calculated <u>as a volume weighted average</u>.**
Development & outlook	Rising balancing energy prices could make this business case more attractive in the future.
Further information:	http://www.nationalgrid.com/UK http://www.elexon.co.uk/ELEXON%20Documents/imbalance_pricing_guidance_note.pdf

<table>
<tr><th colspan="2">4. Offer reserve capacity</th></tr>
<tr><td>Layout</td><td>Offer flexibility to TSO for balancing purposes</td></tr>
<tr><td>Requirements for participation</td><td>Technical requirements
A Fast Reserve provider must:

Have the capability to delivery within 2 minutes of instruction
Have the delivery rate greater than or equal to 25MW / minute
Be able to sustain output for minimum 15 minutes
Halt or start to unwind Fast Reserve delivery within 2 minutes of instruction
Have the unwind rate greater than or equal to 25MW / minute
Deliver minimum 50MW for a single instructable unit or aggregation of more than one unit
Deliver against either constant MW value or known MW profile

A STOR provider must be able to:

Offer a minimum of 3MW or more of generation or steady demand reduction (this can be from more than one site);
Deliver full MW within 240 minutes or less from receiving instructions from National Grid;
Provide full MW for at least 2 hours when instructed;
Have a Recovery Period after provision of Reserve of not more than 1200 minutes (20 hours);
Be able to provide STOR at least 3 times a week.
</td></tr>
<tr><td>Costs & benefits</td><td>

Costs: interface with the TSO must be installed and if necessary, installation costs for load control system and ICT
Risks: Failure to provide contracted balancing energy is sanctioned.
Benefits:

Fast reserve:
Fast Reserve provides the rapid and reliable delivery of active power through an increased output from generation or a reduction in consumption from demand sources, following receipt of an electronic despatch instruction from National Grid. Active power delivery must start within 2 minutes of the despatch instruction at a delivery rate in excess of 25MW/minute, and the reserve energy should be sustainable for a minimum of 15 minutes.
Fast Reserve is procured via a monthly process and requires pre-qualification to establish a Framework Agreement prior to tendering.
<table>
<tr><th></th><th>Generation</th><th>Demand</th></tr>
<tr><td>BMU</td><td>yes</td><td>yes</td></tr>
<tr><td>Non-BMU</td><td>yes</td><td>yes</td></tr>
</table>
Payment Structure:

Optional Service: Providers of the Optional Service will receive an Enhanced Rate Availability Fee (£/h) payment for periods of time where they provide National Grid (following despatch) with enhanced MW run-up and run-down rates. The Enhanced Rate Availability Fee is defined by the provider in the framework agreement.
Firm Service: Providers of the Firm Service will receive an Availability Fee (£/h) for each hour in a Tendered Service Period where the service is available. National Grid will notify ‘windows’ during which it requires the service to be provided, for which a Window Initiation Payment will be made. During a window, Providers may also specify a Positional Fee (the cost of putting plant in a position where fast reserve may be provided). All fees for the Firm Service are submitted by the provider as part of the tender. An utilisation fee (£/MW/h) is payable for the energy delivered in both services (for BMU participants via a bid/offer acceptance). For the firm service this utilisation fee will be capped by the tender parameter submitted.
</td></tr>
</table>

<table>
<tr><td></td><td>Short term operating reserve
Short Term Operating Reserve (STOR) is a service for the provision of additional active power from generation and/or demand reduction. There are two forms of the STOR service Committed and Flexible. Committed service providers undertake to offer service availability in all of the required availability windows in each season and upon accepting the tender, National Grid commits to buy all services offered. Both BMU and Non-BMU are able to tender Committed service. Whilst Flexible service providers are not obliged to offer services in all availability windows and National Grid is not obliged to accept and buy all the services offered and only Non-BMU is able to tender for the Flexible service.
<table>
<tr><th></th><th>Generation</th><th>Demand</th></tr>
<tr><td>BMU</td><td>yes</td><td>yes</td></tr>
<tr><td>Non-BMU</td><td>yes</td><td>yes</td></tr>
</table>
Payment Structure: there are two forms of payment that National Grid will make as part of the service:
- Availability Payments (£/MW/h): service providers are paid to make their unit/site available for the STOR service within an Availability Window.
- Utilisation Payments (£/MWh): service providers are paid for the energy delivered as instructed by National Grid. This includes the energy delivered in ramping up to and down from the Contracted MW level. For BMU service providers this payment will be effected through the Balancing Mechanism.</td></tr>
<tr><td>Further information</td><td>http://www.nationalgrid.com/UK
http://www.elexon.co.uk/ELEXON%20Documents/imbalance_pricing_guidance_note.pdf</td></tr>
</table>

5. Local grid constraints	
Layout	Flexibility allows businesses to minimize their demand peaks and/or regulate power usage across their entire enterprise in function of local grid constraints.
Requirements for participation	• Flexible electricity demand • Atypical load profile

Costs, risks & benefits	• Costs: interface, load management system, ICT costs
	• Risks: none
	• Benefits: benefits for the VPP operator in this business case can be dual:
	  ○ Lower electricity bill if a peak component is integrated in the electricity contract (see also contract optimization)
	  ○ Remuneration offered by DSO for reschedule load for local system management purposes (for the moment, no existing tariff structures are known)

Development & outlook	In the future it is possible, as when different price signals, also known as indirect control (e.g. TOU) or control signals (automated active demand) can be communicated in order to allow intelligent charging algorithms to take generation and grid constraints into consideration, the VPP operator benefits from price opportunities offered by the DSO.
Further information	n.a.

6. Offer grid stabilization services	
Layout	Business-to-business contracts between TSOs and large scale producers/consumers
Requirements for participation	The reactive power provider must •Be capable of supplying their rated power output (MW) at any point between the limits 0.85 power factor lagging and 0.95 power factor leading at the BMU terminals. •Have the short circuit ratio of the BMU less than 0.5. •Keep the reactive power output under steady state conditions fully available within the voltage range ±5% at 400kV, 275kV, 132kV and lower voltages •Have a continuously acting automatic excitation control system to provide constant terminal voltage control of the BMU without instability over the entire operating range of the BMU.
Costs, risks & benefits	• Costs: interface, load management system, ICT costs • Risks: In the case of load shedding contracts, production/operation at the consumer's property may be affected • Benefits:

	National Grid controls Reactive Power through two Balancing Services: The **Obligatory Reactive Power Service** is the provision of varying Reactive Power output. At any given output the Generators may be requested to produce or absorb reactive power to help manage system voltages close to its point of connection. All generators covered by the requirements of the Grid Code are required to have the capability to provide Reactive Power. The Obligatory Reactive Power Service is procured via either Market Agreements or Default Payment Arrangements. Generators can participate in a tender held every six months (for further information see Market Tender Section). National Grid assess the tenders in accordance with the evaluation criteria specified the CUSC. A successful tender then becomes contractually binding. A market agreement is entered into. If a tender is not successful or do not attend a tender, the Generator will be paid on Default Arrangements if they provide the service as instructed. Payment Structure: Market Arrangements whereby the tender allows the Generator to request: - An Available Capability Price (£/MVar/hr) and/or a Synchronised Capability Price (£/MVar/hr) and/or a Utilisation Price (£/MVarh) - The choice of term from a minimum period of 12 months and thereafter in 6-month increments (12, 18, 24, 30, 36 months, etc.). Default Arrangements whereby, in the absence of a market agreement, payment (£/MVarh) is made to generators for reactive utilisation. The payment rate is calculated on a monthly basis by reference to both RPI and Over The Counter (OTC) baseload power indices. **Enhanced Reactive Power Service** is the provision of: •Voltage support which exceeds the minimum technical requirement of Obligatory Reactive Power Service (including Synchronous Compensation); or •Reactive Power Capability from any other Plant or Apparatus which can generate or absorb Reactive Power (including Static Compensation equipment) that isn't required to provide the Obligatory Reactive Power Service. Payment Structure: The tender allows the Generator to request: - An Available Capability Price (£/MVar/hr) and/or a Synchronised Capability Price (£/MVar/hr) and/or a Utilisation Price (£/MVarh) - The choice of term from a minimum period of 12 months and thereafter in 6-month increments (12, 18, 24, 30, 36 months, etc.).
Further information	http://www.nationalgrid.com/UK

3.4.2 Additional business cases in the UK

I) Direct marketing of renewable energy production

UK feed-in tariffs for renewables

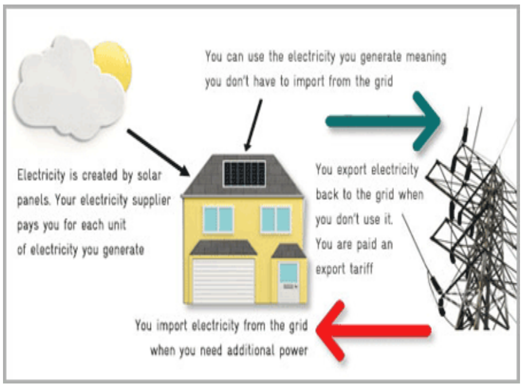
The feed-in tariff (FIT) scheme offers guaranteed cash payments to households who produce their own electricity at home using renewable technologies

Programme to promote widespread uptake of a range of small-scale renewable and low-carbon electricity generation technologies. Suppliers will pay the FITs payments > the 'big six' energy suppliers are required by law– others have opted to offer the payments (list of FITs-licensed suppliers). They also play the main customer-facing role for this scheme: registering eligible installations, processing generation. OFGEM is responsible for running the behind the scenes administration of the scheme ensuring supplier compliance and maintaining the integrity of a Central FITs Register (CFR). The Energy Saving Trust (EST) is the initial contact for residential consumers.

Feed-in tariffs - two tariffs:

- Generation tariff - a set rate for each unit (or kWh) of electricity generated / tariff levels are guaranteed for the period of the tariff (up to 25 years) and are index-linked.
- Export tariff - a further 3.1p/kWh for each unit exported back to the electricity grid – until stage smart meters are installed it is estimated as being 50% of the electricity you generate.

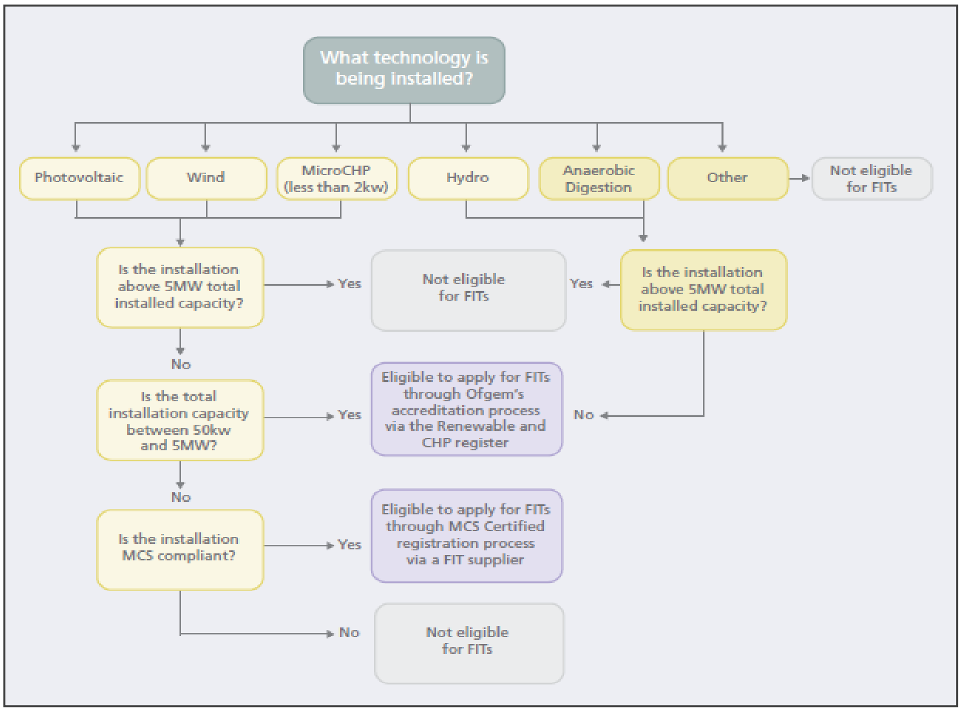
For a full list of generation tariffs, see FIT Payment Rate Table



Sources: [OFGEM 2011d], [OFGEM web] , [Energy saving Trust web]

Eligible installations of between 50kw – 5MW that were installed on or after 1st April 2010 within Great Britain will be able to directly apply for accreditation under FITs as part of the ROOFIT process on the Renewables and CHP Register. www.renewablesandchp.ofgem.gov.uk.

Eligible installations of 50kw or below that were installed on or after 15th July 2009 within Great Britain will be able to directly apply for accreditation under FITs. These installations will be accredited through the Microgeneration Certification Scheme (MCS). More details can be found at www.microgenerationcertification.org.



Source: [OFGEM 2011c]

Feed-in tariffs - proposed changes

Summary of changes: A reduced rate of 21p/kWh (now 43.3p/kWh) for solar PV installations of less than 4kW from 3rd March 2012 + new requirement to show property has an EPC band D or above (9p/kWh if property cannot achieve EPC band D)

Proposed changes from 1st July 2012: Further reductions to solar PV tariffs and reduction of period for which the FIT is paid from 25 to 20 years

Proposed changes from 1st October 2012: Further reductions to FIT rates for renewable electric technologies other than solar PV

[Overview UK Government changes to Feed-in Tariffs]

II) Demand Management

Who can participate?

	Generation	Demand
BMU	n/a	n/a
Non-BMU	yes	yes

Service Description

Demand Management (DM) is a service for the provision of reserve in contingency timescales, via a reduction in active power from demand sites. DM provides a route to market for the Demand Side participation in the provision of Reserve, where potential barriers to participation in the existing Balancing Services have been identified. National Grid encourages the provision of DM via aggregators (or agents) in order to establish a single point of contact for any portfolio of Demand sites.

Why is it needed?

The Demand Management Service is designed to compliment other forms of Reserve provision by encouraging participation from Demand Side service Providers.

Major Technical Requirements

DM service providers must

- Be able to deliver across a minimum of any two consecutive Settlement Periods
- Delivery minimum 25MW from one or more than one site.

In addition to these requirements, in order to allow providers the flexibility to tailor the service to their operational requirements, providers can define additional service parameters such as minimum and maximum 'On Times'

Procurement Process

Demand Management is procured through Bilateral Agreement.

Payment Structure

Demand Management participants only receive Utilisation payments (£/MWh) only for energy delivered as instructed.

More information: http://www.nationalgrid.com/UK

III) Frequency response services

Frequency response services	
Layout	Business-to-business contracts between TSOs and large scale producers/consumers
Requirements for participation	A **Mandatory Frequency Response** provider must: •Have a 3-5% governor droop characteristic (Droop is defined in the Grid Code CC6.3.7 (C) (ii)) as "The ratio of the steady state change in speed in the case of a Generating Unit, or in Frequency in the case of a Power Park Module, to the steady state change in power output of the Generating Unit or Power Park Module) •Be capable to provide continuous modulation power responses to counter the frequency changes via synchronised generation through their automatic governing systems. A **FFR** provider must: •Have suitable operational metering •Pass the FFR Pre-Qualification Assessment •Deliver minimum 10MW Response Energy •Operate at their tendered level of demand/generation when instructed (in order to achieve the tendered Frequency Response capability) •Have the capability to operate (when instructed) in a Frequency Sensitive Mode for dynamic response or change their MW level via automatic relay for non-dynamic response •Communicate via an Automatic Logging Device •Be able to instruct and receive via a single point of contact and control where a single FFR unit comprises of two or more sites located at the same premises. A **FCDM** provider must: •Be available 24 hours a day (declared for full Settlement Periods) •Provide the service within 2 seconds of instruction •Deliver for minimum 30 minutes •Deliver minimum 3MW, which may be achieved by aggregating a number of small loads at same site, at the discretion of National Grid •Have a suitable operational metering •Provide output signal into National Grid's monitoring equipment
Costs, risks & benefits	• Costs: interface, load management system, ICT costs • Risks: In the case of load shedding contracts, production/operation at the consumer's property may be affected • Benefits: National Grid controls System Frequency through three separate Balancing Services: **Mandatory Frequency Response**: All generators caught by the requirements of the Grid Code are required to have the capability to provide Mandatory Frequency Response. The capability to provide this Service is a condition of connection for generators connecting to the GB Transmission System. When service provider delivers the service, they will be paid in accordance with the CUSC section 4.1.3.8 with two types of payment: • Holding Payment: Holding Payment (£/h) is made for the capability of the unit to provide response when the unit has been instructed into responsive mode. Generators submit holding prices on a monthly basis through the Frequency Response Price Submission System (FRPS). • Response Energy Payment (£/MWh): Remunerates the amount of energy delivered to and from the system when providing Frequency Response The response energy payment for a settlement period is calculated based on the formula below: *Response Energy MWhrs * the Market Index Price *Factor* *Where;* *If the response energy is Low Frequency response energy (Additional Energy), the factor is 1.25.* *If the response energy is High Frequency response energy (Reduced Energy), the factor is 0.75.* **Firm Frequency Response (FFR):** FFR is the firm provision of either a Dynamic or non-Dynamic Response to changes in the system frequency. The key differences between FFR and Mandatory Frequency Response are: under FFR services can be provided by parties outside of the Balancing Mechanism and; a firm agreement regarding utillisation is made in advance of service provision.

	Payment Structure: FFR has a four-part payment structure. However, providers do not have to tender in all these payments. Please see below for illustrative example. - Availability Fee (£/hr) – for the hours for which a provider has tendered to make the service available for. - Tendered Utilisation fees - Window Initiation Fee (£/window) – for each FFR nominated window that National Grid instructs within the Tendered Frames. - Nomination Fee (£/hr) – a holding fee for each hour utilised within FFR nominated windows. - Tendered Window Revision fee (£/hr) - National Grid notifies providers of window nominations in advance and, if the provider allows, this payment is payable if National Grid subsequently revises this nomination. - Response Energy Fee (£/MWh) – based upon the actual response energy provided in the nominated window **Frequency Control** by Demand Management (FCDM): Frequency Control Demand Management (FCDM) provides frequency response through interruption of demand customers. The electricity demand is automatically interrupted when the system frequency transgresses the low frequency relay setting on site. The demand customers who provide the service are prepared for their demands to be interrupted for a 30 minute duration, where statistically interruptions are likely to occur between approximately ten to thirty times per annum.
Further information	http://www.nationalgrid.com/UK

4 Glossary

Aggregator
The *aggregator* can be seen as an actor who aggregates the flexibilities (in production and consumption) provided by consumers and offers this flexibility to different market participants.

Balancing Responsible Party (BRP)
Balancing responsible parties are required to pay for the imbalances created by the parties they represent. BRPs consolidate the imbalances of the parties they represent and are charged for the imbalance in their portfolio by the TSO. The imbalance of a given BRP is the quarter-hourly difference between the total injections within his portfolio and the total offtakes within his portfolio.

Centralised electricity producer
Electricity producer with generator(s) connected to a high-voltage transmission grid. Production can be dispatchable and/or non-dispatchable.

Consumer
Entity purchasing electricity for powering its loads. It may be “passive” in the sense that it determines its consumption entirely with respect to its own needs, or “active” in the sense that it can interact with other players to determine or alter its consumption. Certain consumers may also have their own production and/or storage capacity (sometimes referred to as prosumers).

Decentralised electricity producer
Electricity producer with generator(s) connected to a medium or low-voltage distribution grid. Production can be dispachable and/or non-dispachable.

Distribution System Operator (DSO)
Regulated entity responsible for the transport of the electrical power on the distribution networks (e.g. between the high voltage Transmission system and the end consumer). They provide access to the distribution network users according to non-discriminatory and transparent rules. In order to ensure the quality and security of supply, they also guarantee the safe and economic operation and the maintenance of the distribution grid.[3]

DSOs have to provide system services such as voltage control, network restoration, etc. Depending on the type of distribution network and its capability, they may also control the power flows on the distribution and may alter the decentralised generator schedules to manage constraints and congestions on the network. They are generally in control of all system switching for scheduled and emergency outages.

Being regulated, a DSO is generally forbidden to act in a way that competes with deregulated entities. It is often also referred to as a Distribution Network Operator (DNO).

Market operator
The *market operator* is responsible for the wholesale market trade.

[3] Ibid., p. 126

Transmission System Operator (TSO)
Entity responsible for the bulk transmission of electric power on the main high voltage electric networks. TSOs provide grid access to the electricity market players (i.e. generating companies, traders, suppliers, distributors and directly connected consumers) according to non-discriminatory and transparent rules. In order to ensure the security of supply, they also guarantee the safe operation and maintenance of the system.

TSOs have to provide reliable and economic system services such as frequency and voltage control, network restoration, stability control, etc. TSOs may alter generator schedules to maintain the power balance between generation and demand, and manage constraints and congestions on their network. They are generally in control of all system switching for scheduled and emergency outages, although the network owners may do the actual switching. In many countries, TSOs are also in charge of the development of the grid infrastructure too.

The roles of transmission system operator and transmission network owner are often combined, but do not need to be. They may also be responsible for oversight of parts of wholesale electricity markets (as market operators).[4]

Prosumer
The term prosumer comes from the contraction of producer and consumer; a prosumer is therefore a consumer who has generation and/or storage capabilities in its premises (e.g. embedded generation such as photo-voltaics, micro-turbine, etc.).

Retailers
The principal functions of the *retailer* are purchasing electricity on the wholesale market and selling it to the consumers. Retailers have a balancing contract with a BRP, so that differences between scheduled offtake and real offtake can be dealt with.

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[4] See also ADRESS Plattform (ed., 2011):
Deliverable 1.1 - ADDRESS technical and commercial conceptual architectures, Appendix A, p. 129
Available at http://www.addressfp7.org/config/files/ADD-WP1_Technical_and-Commercial_Architectures.pdf