This is the fourth and last newsletter of the IMPROGRES project. The IMPROGRES project aimed at improving the market integration of distributed generation (DG) and electricity from renewable energy sources (RES-E) in European electricity markets. The project supports all stakeholders that are involved in achieving the ambitious national and European policy targets regarding renewable energy and greenhouse gas emission reduction.

The IMPROGRES project lasted from September 2007 to March 2010. This newsletter summarizes the main findings of the project. Hopefully it will make you interested to obtain more information, which you can find on the project website www.improgres.org.

Achieving the European target of 20% reduction of greenhouse gases in 2020 relies for a major part on increasing the share of renewable electricity generation, and more efficient fossil fuel based generation in combined heat and power installations. Most of these renewable and CHP generators are smaller in size than conventional power plants and are therefore usually connected to distribution grids instead of transmission grids. Different support schemes for renewable energy sources (RES) have been successfully implemented and have resulted in a rapid growth of distributed generation (DG). IMPROGRES scenario analysis shows that the installed capacity of DG in the EU-25 is expected to increase from 201 GW in 2008 to about 317 GW in 2020. A large part of this increase will be made up of more variable and less controllable renewable energy sources like wind and photovoltaics.

The increase of those ‘intermittent’ renewable energy sources does not only change the generation mix, but also influences other sectors of the electricity supply chain, especially markets and networks. There is a recent tendency towards the implementation of more market-based financial support instruments such as the feed-in premiums currently applied in Denmark, the Netherlands and Spain. Such subsidies on top of the electricity prices create an additional incentive for flexible DG units to follow demand patterns by generating electricity when prices are high. This process of market integration stimulates DG to become more responsive to the overall electricity generation and demand situation.

While the process of market integration of DG has started, network integration of DG in distribution networks has not yet received sufficient attention. Integration goes beyond merely connecting new DG units, by including whenever possible the potential of DG in improving system operation by reducing network losses or preventing system peaks. Network operators also have to deal with more fluctuating power flows and frequent situations in which electricity production exceeds demand and has to be exported to other regions. These issues are likely to result in barriers for further DG development, if network integration is not improved.

The EU-funded IMPROGRES project (Improvement of the Social Optimal Outcome of Market Integration of DG/RES in European Electricity Markets) has analysed the impacts of large-scale deployment of distributed generation for the whole electricity supply system. As the viewpoint of society is taken, impacts outside the network are also included. But the primary focus in IMPROGRES has been on the integration of distributed generation in distribution networks. All electricity generation in distribution networks is included as DG. Part of this DG consists of renewable electricity generation (RES), while the non-renewable part mainly consists of Combined Heat and Power (CHP) generation. In order to take due account of the interactions between different electricity system segments, the analysis assesses the impact on the total supply system for three distribution networks in Germany, Spain and the Netherlands, which have a substantial amount of DG and quantitative data available.
Support schemes for renewable energy
Financial support schemes for RES and efficient CHP remain crucial in the coming decade to achieve the EU 20-20-20 targets. In the initial stages of market penetration of a technology, characterized by low penetration levels, high cost and high risk, support schemes providing high investment security, such as the fixed feed-in tariff, are typically implemented. During the transition more market signals are successively incorporated until a technology reaches the commercial stage and becomes competitive with other technologies in the absence of support.

Case studies of system integration
In three case studies, detailed cost estimates were made to quantify the impact of rising shares of DG on electricity networks. All electricity generation and loads connected to distribution grids were included, with the exception of offshore wind and large-scale hydro, which are usually directly connected to high-voltage transmission grids. Distribution network costs are driven by a number of factors. Three main factors are the relative level of demand and DG, their spatial overlap, and the network management philosophy applied. If DG makes up a small percentage of the electricity demand, network costs usually increase only modestly. However, with larger shares of DG compared to the load, substantial extra network investments as well as higher losses are usually unavoidable. Local generation, closer to the point of use than in case of large-scale generation, can lead to slightly smaller grid capacity requirements and to somewhat lower electric losses. The level of the distribution network costs is also related to the ‘fit-and-forget’ network planning philosophy, which means that the network itself is prepared for all possible network situations and no active contribution of generation and demand to network operation is expected. When the variability of network flows increases due to intermittent production, passive network management may no longer be the most favourable type of network management.

Response options for minimising costs of DG integration in networks
The increasing supply from intermittent renewable energy sources adds an additional source of fluctuations to the generation mix, which increases system integration costs, especially distribution network costs. In order to limit the growth of these network costs, Active Network Management (ANM) is often mentioned as a solution. With ANM the operational management is changed; all possible demand and generation situations are no longer resolved in advance through network reinforcements. Part of them are resolved in a smart way (i.e. ‘smart grids’) in the operational time frame by means of ICT (Information and Communication Technologies)-related measures. In this way, bi-directional electricity flows can be controlled by measures such as condition monitoring and fault analysis. Furthermore, connected customers are enabled to contribute to optimal network operation by deploying their flexibility in either generation or consumption. Both aspects of ANM have the potential to reduce peak currents in the grid, thereby providing opportunities for network cost savings due to reductions in network investments and electric losses. In the case studies a cost savings potential was found of about 5-10% of the additional network cost. Extrapolating these findings to the EU-27 would imply network cost savings due to active network management of about € 1-3 billion in the period up to 2020.

Regulatory issues for better integration of DG in networks and markets
Five key regulatory issues concerning the integration of DG in networks and markets are elaborated below: network cost recovery, network innovation, network planning, network charging and providing incentives for demand response.

a) Network cost recovery
Current network regulation does not yet (fully) consider the effects of the energy transition taking place. Regulators often do not allow for network costs caused by the increasing amount of energy produced by DG in the efficiency assessments of DSOs. Consequently, network costs for the integration of DG are not fully recovered by DSOs in areas with large increases of DG.

b) Network innovation
Regulation often does not allow for realization of full (long-term) potential benefits of ANM for both markets and networks. The benefits of ANM type of innovations are only partly experienced by DSOs; part of the benefits flow to other parties in the electricity value chain like generators, suppliers and loads. When DSOs experience full costs but not full benefits of investments in ANM, this
affects their trade-off between conventional network solutions and ANM. Consequently, in a number of cases they will be inclined/biased to invest in conventional grid solutions instead of ANM. Therefore, some smart grids projects will not be realized although these are preferable for the country as a whole. One exception is the UK, which has introduced the Innovation Funding Incentive (IFI) to allow for recovery of eligible innovative investments.

\[ c) \text{ Network planning} \]
Proper mid-term planning procedures should be in place to anticipate future flexible and additional load. This should be incorporated in distribution network planning. One fundamental challenge is to find the economic optimum between the necessary costs of network extension and benefits of system flexibility enhancing DG/RES integration measures at DSO level.

\[ d) \text{ Network charging} \]
When distribution grids are increasingly dominated by the requirements of distributed generation, the remaining grid reinforcement costs can no longer be unambiguously attributed to load only. A future with high penetration rates of both load as well as production calls for allocation of part of the grid reinforcement costs to generation. Consequently, Member State governments and regulators are advised to consider the introduction of use-of-system (UoS) charges for generators. A shallow connection charge approach is recommended as this provides a fair and transparent access treatment for DG investors. The remaining costs for integrating distributed generators in networks are at least partly covered by UoS charges. These Generation UoS charges should be in line with the level of GUoS charges to be introduced at the same time for large conventional generators to balance the impact on the competitive environment of DG producers. This would give generators due financial signals of the network-cost-consequences of their interactions with the public electricity grid. Additionally, time-of-use signals may contribute to lower network peak demand by shifting generation and consumption to times with lower network utilization. This can be relevant in case a sufficient amount of flexible DG is present. For those cases, UoS charges should preferably be made time-dependent. In the longer term, where applicable, DSOs should be incentivised to supplement UoS charges with locational signals.

In that way, potential DG investment will face reduced UoS charges at locations where DG investment has a positive network impact and the other way around. For transparency reasons, it is recommended to provide locational signals directly through network charges.

\[ e) \text{ Demand response} \]
Currently, demand response is nearly non-existent, because very few customers have contracts that include real-time or near real-time price information. In several Member States the roll-out of smart meters among low-voltage customers is ongoing, in order to increase the responsiveness of the demand side of the electricity system. This should be accompanied by sending consumers price and/or volume signals, because otherwise customers will probably not react. These price signals would constitute differentiated energy prices. Common schemes are time-of-use (TOU) prices, real-time pricing (RTP) or critical peak pricing (CPP). Volume signals are limitations on the consumption of specific loads during a certain time span through, for instance, interruptibility contracts. Additionally, demand response programs ought to be defined and progressively implemented, starting with those customers that already have smart meters. It is important to carefully define the role of each of the agents involved, especially for the retailers. Home automation ought to be developed and promoted to harness the demand response potential to a larger extent. Evidently, the functionalities of the "smart meters" that are being installed should enable endorsement of such applications.

Regulatory priorities for meeting the EU-2020 targets
A major contribution to the EU objectives towards achieving improved sustainability, security of supply and competitiveness in the energy sector will come from harnessing the potential flexibility in electricity demand and in distributed generation. Regulated network companies have a role in facilitating this process by developing sufficient network capacity, and by establishing advanced metering and communication infrastructure at every grid connection. However, a major part of the benefits of smarter grids are outside the regulated domain, affecting the relation between customers and their energy suppliers or energy services companies. As a con-

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sequence, network regulation should give a prominent place to 'external effects': cost and benefits outside the network. Developing the infrastructure for smart metering and control of distributed generation and demand response are more likely to lead to financially viable 'smart grids projects' when not only viewed from a network cost-benefit perspective, but also including other electricity system benefits.

The main regulatory recommendations from the IMPROGRES project are:

- Choose for shallow connection charges to lower the barriers for distributed generation and to simplify connection procedures.
- Introduce Generation Use of System charges to provide better incentives for improved network utilization of distributed generation, and to improve the financial position of those Distribution System Operators (DSOs) with larger shares of distributed generation.
- Introduce more incentives for DSOs, preferably output-based, to internalize in DSO investment decisions the favorable effects of smart grid solutions for other electricity system actors.
- Support the establishment of a smart metering infrastructure as the precondition for further market integration of distributed energy resources.
- Depending on availability of smart meters, flexible network tariffs should be introduced, at least using Time of Use tariffs, and wherever relevant and possible, also locational incentives.

For more information: visit the project website: www.improgres.org or contact the project coordinator: Frans Nieuwenhout, nieuwenhout@ecn.nl tel. +31 224 564849

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- Union Fenosa Distribución, Spain
- Institut für Solare Energieversorgungstechnik (ISET), Germany
- Risø, DTU, Denmark
- MVV Energie, Germany
- Liander NV, The Netherlands

For more information see: http://www.improgres.org

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