Unleashing the Flexibility of Gas: Innovating Gas Systems to Meet the Electricity System's Flexibility Requirements

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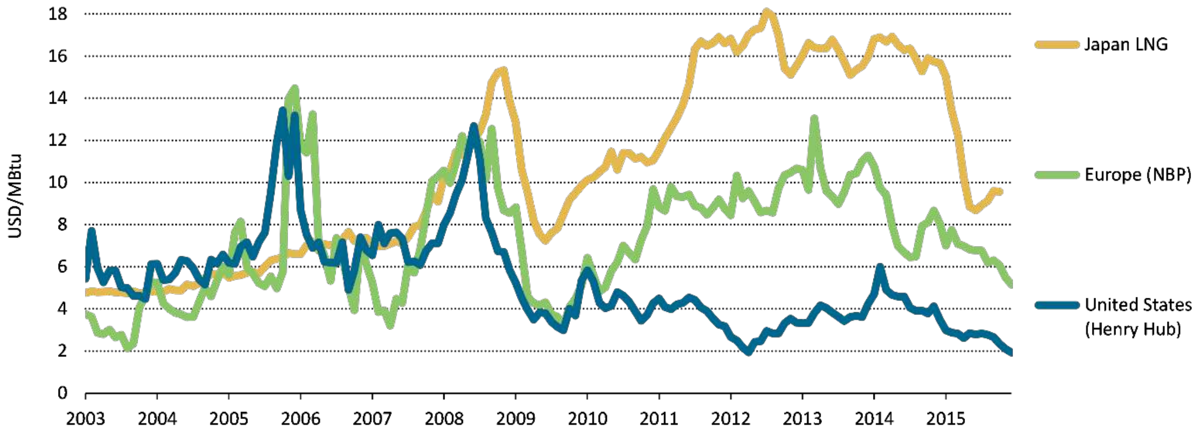
1. Introduction: The gas-electricity nexus

The energy system is a complex system of physical infrastructure and markets that interact with each other. Within this system, the gas and electricity systems have become the backbone of modern energy systems. Both systems are closely interconnected due to the vast deployment of efficient combined cycle gas turbines (CCGTs), mainly in OECD countries in the first decade of the 2000s. This increased interdependence and rapid penetration of variable renewable energy sources (varRE) make the gas-electricity nexus a primary concern and opportunity for energy system flexibility.

The significant gas price discrepancies across the world (Figure 1) witness that gas markets remain largely regional. The role of gas in electricity systems and the gas-electricity interaction differs though across the globe:

- In the US, natural gas has become one of the major energy sources, primarily at the expense of coal investments, due to the shale gas revolution and potential for implementing the CO_2 reduction policies introduced by EPA. Consequently, the gas network has been stressed during times when demand from both the electricity system and direct gas consumers is high. Several coordinating initiatives between gas and electricity sectors to ensure reliable operation have emerged across the country (e.g, California, Texas, New England and the Midwest).
- Latin America is one of the world's most hydro dependent regions, but recently has suffered prolonged droughts that have generated numerous operational and system planning issues. This renewed interest in conventional thermal investments for dispatchable generation, as demand for both fossil fuel and electric power continues to grow rapidly across the region. Gas market continues to grow, owing in part to ample investment in new liquefied natural gas (LNG) infrastructure planned in Chile, Colombia and Uruguay.
- In Eastern Asia, natural gas tends to be a scarce resource that is today mainly imported through LNG terminals. Gas-fuelled electricity generation is used at best as mid-load generator, except for Japan, where after the Fukushima disaster, CCGT plants operated as base load plants. Coal remains king though, but the role of gas could expand given concern over local air pollution and the increasing availability of pipeline gas from Russia and central Asia. China has technically the world's largest recoverable shale gas resources. However the potential is constrained by geological complexity, shortages of water, land access, and the limited experience of the industry, which led the country to lower its production targets. China's gas consumption was increasing faster than its production over the past 5 years. This trend is likely to continue since the 13th Five-Year Plan (2016-2020) requests that coal in non-power sectors is replaced either with natural gas and electricity.
- In Europe, gas power is considered an important technical resource for renewables' integration, but it is currently struggling to be economically competitive: several gas power stations have been mothballed and utilities are calling for payment mechanisms to keep plants online. The situation has been aggravated by flat or, in some countries, declining electricity demand, low coal prices and weak carbon markets. In parallel,

efforts to decarbonise the gas network and reduce import dependence are increasing: biogas production is increasing, although from a small base, and several power-to-gas demonstration projects have been commissioned.



Note: NBP = National Balancing Point (United Kingdom), representative of European gas prices

Source: International Energy Agency (2016), Tracking Clean Energy Progress 2016, OECD/IEA, Paris

Figure 1: Gas pricing at different global trading hubs, 2003-16

In all these regions, the inevitable penetration of variable generation and electrification of heat and transport will lead to an increasingly variable operation of thermal dispatchable generators, as is already observed in Europe. The increasing net-load variability is affecting not only power stations, but also networks and gas supply systems (e.g., gas storage and LNG tanks). This article discusses the capability of the gas system to meet the electricity system flexibility requirements and explores technical, economic and policy measures required to make gas a flexibility resource.

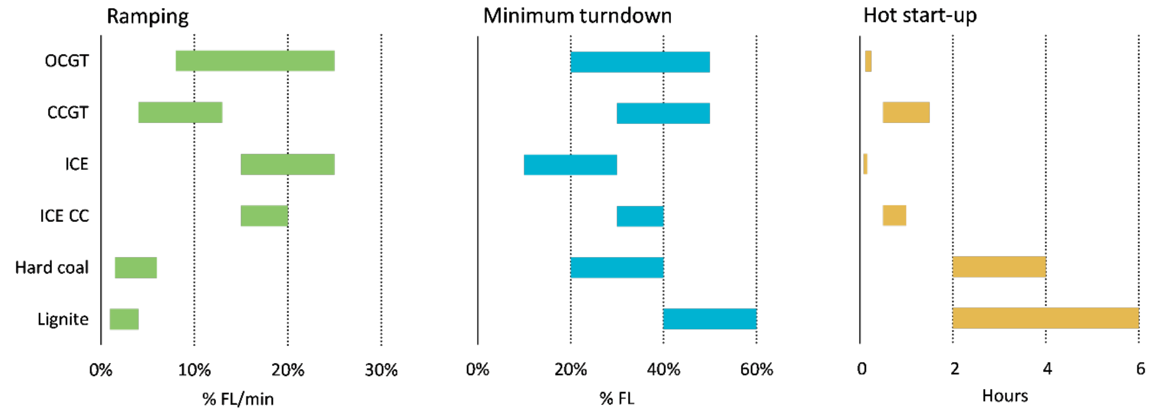
Flexibility in three parts of the system is analysed in this article:

- Flexibility from gas power generation: Technology and electricity market design
- Flexibility in gas supply: Gas storage and gas-electricity market coordination
- Flexibility through multi input/output plants and appliances

2. Flexibility from gas power generation: Technology and electricity markets

2.1. Impacts of flexible operation and technology development

From a technical perspective, gas turbine-based plants are typically more flexible than many other forms of generation, capable of starting quickly and with significant ramping capability. Therefore it is in many cases an ideal complement to variable renewable energy. For example, Ireland has simultaneously a very large penetration of wind and gas fired electricity generation. (Figure 2). Modern gas turbine plants excel with start-up times of less than one hour and ramp rates above 50 MW/min. Older coal plants, heavy oil and nuclear plants often require 4-8 hours to start-up and have lower ramp rates (few MW/min).

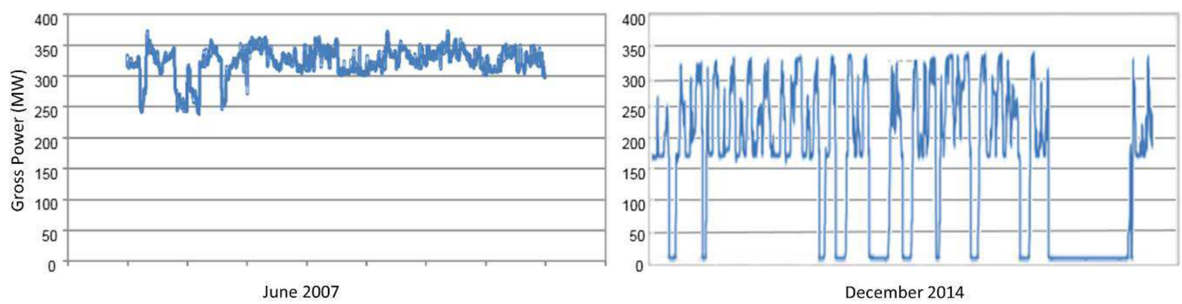


Notes: FL = full load. Typical plant size (MW) is as follows: Black coal: 500-1 000; lignite: 500-1 000; CCGT: 300-500; GT: 50-200; recip: 20-200; and recip CC: 250-450. Nuclear plants are excluded since they perform worse.

Sources: International Energy Agency (2014), Energy Technology Perspectives 2014, OECD/IEA, Paris, DIW (German Institute for Economic Research) (2013), Current and Prospective Costs of Electricity Generation, Berlin; VDE (*Verband der Elektrotechnik Elektronik Informationstechnik*, in English German Association for Electrical, Electronic & Information Technologies) (2012), Erneuerbare Energie braucht flexible Kraftwerke – Szenarien 2020, Frankfurt am Main

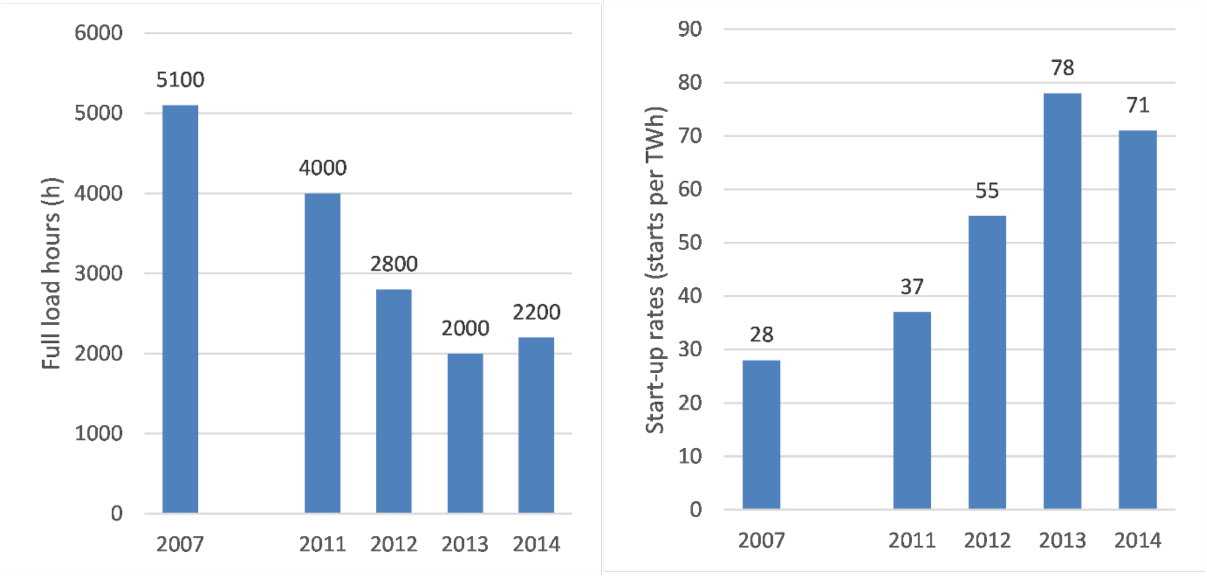
Figure 2: Flexibility characteristics of thermal electricity generation plants

Open-cycle (OCGT) and aero-derivative (ADGT) gas turbines were always designed to provide flexibility, but combined cycle power plants (CCGT) were initially designed to operate mid to base load. Over the last decade, European CCGTs have already evolved to a point where it is common that they have a more flexible operating schedule. In some European regions, CCGT dispatch has moved from base to mid-load to several start-up/down cycles per day since the mid-2000s (Figure 3). Operating hours consequently decreased to as low as 1 300 hours per year, while start-up rates are increasing from 25 starts per TWh to more than 80 starts per TWh produced (Figure 4). The increased cyclic operation exposes gas plants to more wear and tear and consequently increases cycling cost.



Source: ENEL

Figure 3: Example of the operation schedule of the same CCGT in 2005 and 2013 in Italy



Source: ENEL

Figure 4: Equivalent Operating Hours and start-up rates (starts per TWh) for CCGT plant in Italy owned by ENEL

Gas turbine R&D focusses on improving the technical flexibility as well as economic profitability in electricity markets by minimising start-up times, enhancing ramping capabilities and reducing minimum stable output of gas power stations. The R&D priorities for gas power plants are the following:

- Use of advanced materials to minimise cycling impact and cost. In particular, in CCGTs, improve balance of plant (BOP) and heat recovery steam generator (HRSG) that often limits start-up times since the material and equipment cannot sustain higher temperature gradients. Improved maintenance procedures in combination with new control instruments (potentially in real-time) can also optimise the start-up procedure and reduce start-up times.
- Increased use of monitoring and automatization for reliable start-up sequence. For CCGTs, additional monitoring systems help to identify stress and residual life on steam turbine and HRSG
- Maximize load gradients during load changes with use of advanced materials and real-time monitoring systems to minimize wear and tear of the material
- Improve combustion stability in gas turbines during load change
- Reduce turn-down ratio and maximize part-load efficiency, especially of the gas turbine, by improving the combustion process and burner materials.

Turbine-based plants today completely dominate the gas power sector, but could potentially face competition of reciprocating engines in some cases. In the past, reciprocating engines have mainly only been used for small decentralised applications since turbine efficiencies are considerably lower for small these applications (<10 MW) and since reciprocating engines can burn a broader range of fuel compositions (pipeline quality gas and e.g. synthetic natural gas, landfill gas, and biogas). However reciprocating engines are now available in sizes of up to 20 MW and can be organised as banks of engines to form a large power plant (>200 MW). Many gas turbine manufacturer now in fact own also reciprocating engine companies (Table 1). These plants, provide cost-effective N-1 reliability for islanded power systems due to the scalability of the cascading plants that require only one additional reciprocating engine to meet the reliability standard. With regard to flexibility characteristics, reciprocating engines could provide

- higher efficiency than OCGT and ADGT (up to 48%)
- higher part load plant efficiency and very load minimum output given that plant (20-200 MW) is based on small units (<20 MW)
- very quick start-up time (few minutes) and good ramping.

Table 1: Gas turbine manufacturers and their related reciprocating engine companies

Gas turbine	ICEs
GE Turbines	Jenbacher, W**aukesha**, Dresser
Rollce Royce	Bergen
Solar Turbines	CAT Power
MAN Turbo	MAN
Mitsubishi Heavy Industries	Mitsubishi Heavy Industries

2.2. Electricity market design to reward flexibility

From an economic perspective, increasing levels of variable renewable energy penetration may reduce the running hours of these gas generators. Modelling of the UK system indicates that the capacity factor of CCGTs could drop from around 45% today to as low as 10% in 2050. Additionally, the more frequent start-ups and higher ramps result in higher cycling costs. This potentially raises economic concern for these gas plants as there will be a reduction in revenue and an increase in cycling costs. This challenge has contributed to an extensive and global debate on the design of electricity markets that reward flexibility and maintain adequacy. For example, in Europe many state of the art gas plants have been mothballed as they are no longer in the merit order (a problem that is not only caused by increased variable renewable generation but also by the relative market prices for coal and gas), and many others are struggling to continue to operate. This has led to the development of capacity mechanisms and other market measures for some of these gas plants. In Ireland new ancillary service products are being defined in order to reward flexibility, and gas plants are potentially providers of these services. New market products are also being developed in some parts of the US, notably California and MISO.

The best type of gas plant to have in these high penetration of varRE scenarios is highly dependent on local circumstances. OCGTs are more flexible than CCGTs but are less efficient, and therefore there is a market trade-off between energy and flexibility. There are other designs such as Aero-derivative gas turbines (ADGTs) and reciprocating engines which combine flexibility and efficiency but do so at the expense of additional capital expenditure.

Economic profitability mainly on market revenues and technology cost will also define how gas power plants perform against other flexibility sources, in the electricity system (interconnection, demand-side control, consumer interaction) and in the wider energy system (heat, water). The most economic form of flexibility will be system specific. However, when combined with capacity requirements gas plant would be particularly suitable. Market design and rewarding flexibility is essential to encourage investment in flexibility and ensure reliability.

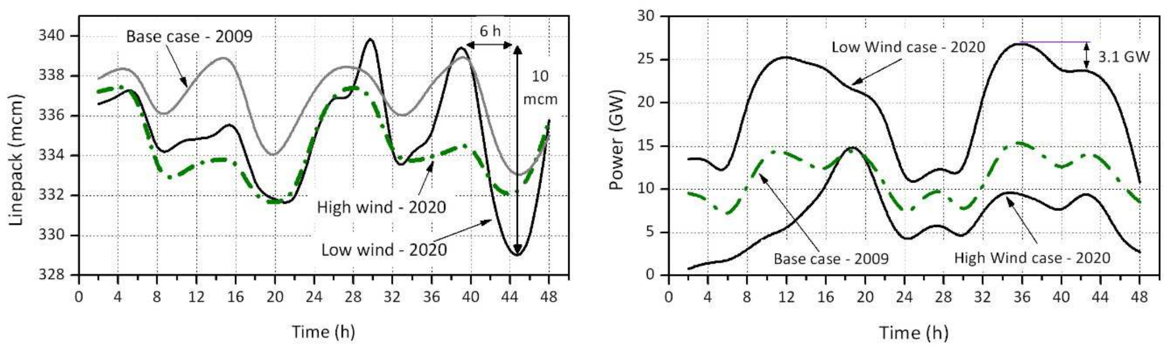
3. Flexibility in gas supply: Gas storage and gas-electricity market coordination

4.1. Gas storage

In the past, gas network flexibility appeared abundant compared to electricity systems and was largely ignored in electricity reliability assessment. The variability of varRE in the electricity system will lead to a more flexible operation of gas power station which ultimately translates to diurnal variability in gas supply and may require that gas is stored in preparation for a ramping event in the electricity system. Compared to electricity systems, the gas systems typically offer significant flexibility due to different storage options: line-pack, underground storage and LNG tanks.

Line-pack is the volume of gas stored in pipelines and can be used to meet abrupt diurnal changes in gas demand. It is proportional to average system pressure. During a period of low renewable energy output – for example, wind – gas generators may be called upon, which would lead to a large and rapid decrease of the gas line-pack. If this happens when peak gas and electricity demand coincide, the resulting pressure drop in the gas network may limit its ability to meet rapid changes in gas demand (including gas for power generation) and cause interruption of gas supplies to CCGTs. Other flexibility sources (e.g. electricity imports through interconnectors or demand-side response) would be required to ensure reliable operation of the systems. To mitigate such line-pack shortages, coordination between gas network and electricity system operators will be increasingly important.

Modelling results for the UK 2020 system indicate the increasing coordination requirements between gas and electricity system operation. In a low wind scenario, the line-pack decreases strongly if high demand coincides and limits the gas supply to CCGTs. As a result, the power output from CCGTs during peak hours may drop by almost 3 GW (Figure 5). This reduction in the power output of CCGT was compensated by the import of more expensive electricity from the UK-France interconnector.



Source: Qadrdan et al. (2010)

Figure 5: Aggregate gas network line-pack (left) and power generation by CCGT (right)

Underground gas storage facilities include depleted gas/oil fields, aquifers and salt caverns. Depleted fields and aquifers are typically used as seasonal storage facilities. Natural gas is injected into storage during the summer (low demand season) and withdrawn during the winter (high demand season). The withdrawal rate and capacity is often very large, but the cycling capability is limited. Salt caverns are commonly used as fast cycle storage due to their ability to support several cycles of gas injection into and withdrawal from storage within a year. This type of storage is better suited to provide gas supply flexibility to electricity systems with high penetrations of varRE. Despite the receding gas demand in Europe, the number of European storage facilities is increasing due to growing flexibility requirements as well as security of supply concerns. The completion of the currently planned projects, mostly salt cavern facilities, will increase storage capacity by 20% in 2020 compared to current levels.

Liquefied Natural Gas (LNG) storage tanks and gasification stations are used as peak shaving facilities which can rapidly respond to sudden gas demand changes. They are therefore not only contributing to energy security by diversifying supply but also provide operational flexibility.

4.2. Gas–electricity market coordination

Gas and electricity markets interact through gas power plant operators that buy their fuel on gas markets, in order to generate power and sell it to the electricity market. Plant operators may do so by trading in a variety of markets, i.e., from long-term contracts and forward markets until shortly before real time. Whilst longer term transactions are mainly important with a view to the need for sufficient gas network capacity, flexibility needs are primarily driven by trading in the day-ahead and intra-day / within-day markets as well as the provision of ancillary services and balancing energy to power system operators in real time.

Electricity and gas markets are often operated in isolation on different timeframes throughout the day and have often failed to create a homogenous structure. Among others, some of the key challenges include the following:

- Different timescales, such as the difference between the 'gas market day' (6 AM to 6 AM) and the calendar day, or the use of sub-hourly settlement intervals in electricity systems,
- A system of fixed 'gates' (day-ahead and/or during the day) at which electric power and/or network capacity is traded in the electricity markets as opposed to continuous trading in the gas market,
- Different product definitions and mechanisms for allocation of network capacities,
- Wide-spread use of interruptible network capacities in the gas market.

As a result, gas plant operators may be required to commit to a certain gas volume before knowing if their electricity market bids have been accepted, or vice versa. As gas plant operators need to account for such risks in their bidding behaviour, this may result in a suboptimal market outcome and increased costs to consumers. Similarly, gas network operators are often unable to predict the variability in gas offtake induced by the electricity market, making it difficult to manage diurnal flexibility (such as line pack) in an optimal way.

As the deployment of varRE progresses, limited market coordination may lead to serious risks for flexibility, such as the need for quickly ramping up generation by gas-fired power plants. In recent years, the lack of coordination between gas and electricity has already threatened reliability. For instance in Texas, insufficient stocks of natural gas in local storage contributed to the need for rolling blackouts in February 2011. Similarly, in February 2012, parts of the South German power system were close to breakdown due to not considering the gas-electricity system interdependence. A cold spell had driven electricity demand to record highs, while direct gas demand for heating was also high. As they had only contracted for interruptible gas pipeline capacity, some gas power plants could not be dispatched as required, and a rolling blackout could only be avoided by actively reducing demand.

In response to these concerns, regulators and governments are increasingly encouraging coordination between both markets. In the US, gas and electricity coordination activities and interdependence assessment are ongoing in various regions, namely California, Texas, New England and the Midwest. Likewise, this topic has been picked up both at a national and European level in Europe. Besides improved coordination and information exchange between system and network operators for gas and electricity, some of these initiatives have also suggested changes of market design and network access arrangements. For instance, in France, the gas transmission system operator introduced a set of specific operating restrictions for a growing fleet of gas-fired plants, but in combination with a new commercial product, which allows such plants to purchase additional diurnal flexibility on a daily basis.

To a certain extent, the coordination challenges are linked to different time constants in electricity and gas balancing (compare Table 2). Whilst an efficient integration of varRE requires shorter gate closure times and settlement intervals, physical gas pipeline flows can only be changed with a significant delay. This creates a dilemma for gas-electricity market coordination as well as natural barrier for alignment of market opening/closing times. To a certain extent, regulators and system operators thus have to make a choice between either exposing gas power plant operators to the risk of diurnal restrictions and different timescales for the gas and electricity market, or allocating the risk of variations in the last 2 – 3 hours to gas network operators.

Table 2: Different time constants in electricity and gas balancing

Issue	Electricity System	Gas System
Balancing requirement	Need to maintain system frequency within strict limits in real time	Maintain operating pressures within a certain range due to line-pack capability
Balancing process	Close to real time (< 1 sec) <u>power</u> balance	Cumulative <u>energy</u> deviation over balancing time frame or day
Balancing time frame	Focus on immediate action in last minutes-hour before real time	Focus on delayed actions (ex-post) (typically ≥ 2 hours)

Adapted from DNV GL

4. Flexibility through hybrid energy conservation systems

Integrated energy conversion systems can provide high levels of flexibility when they can switch between input - energy resources - and output - production service – as well as being able to store the input resource and/or some intermediate or final form of the converted resource. Such a system is commonly referred to as multi-input poly-generation conversion system, multi input-output conversion system, energy hubs or hybrid energy conversion system (HES). The flexibility can be utilized for the electricity system or the natural gas system, or both. Two kinds of flexibility can be distinguished for HESs:

- Operational flexibility enables meeting highly variable net loads or maximise operation at steady state of a certain HES appliances to minimize wear and tear.
- Economic flexibility enables arbitrage between input resources and output services, i.e., utilizing least-price input resource while providing highest price output service, subject to contractual and physical constraints. A traditional single input single output power plant may provide significant operational flexibility, but it would not have economic flexibility.

4.1. Examples of advanced HES designs

A combined heat and power or cogeneration plant fuelled by natural gas and biogas is a familiar design that exemplifies an HES. However, a large variety of alternative HES designs are conceivable by combining different inputs (e.g. electricity, heat, fuels, and/or biomass) and outputs (e.g. electricity, heating and cooling services, water, hydrogen, transportation fuels, and/or commodity chemicals). The flexibility benefits of HES deployment are exemplified here based on three different HES designs: an advanced HES based on anaerobic digestion (AD), hybrid residential heaters and wind-electrolyser systems.

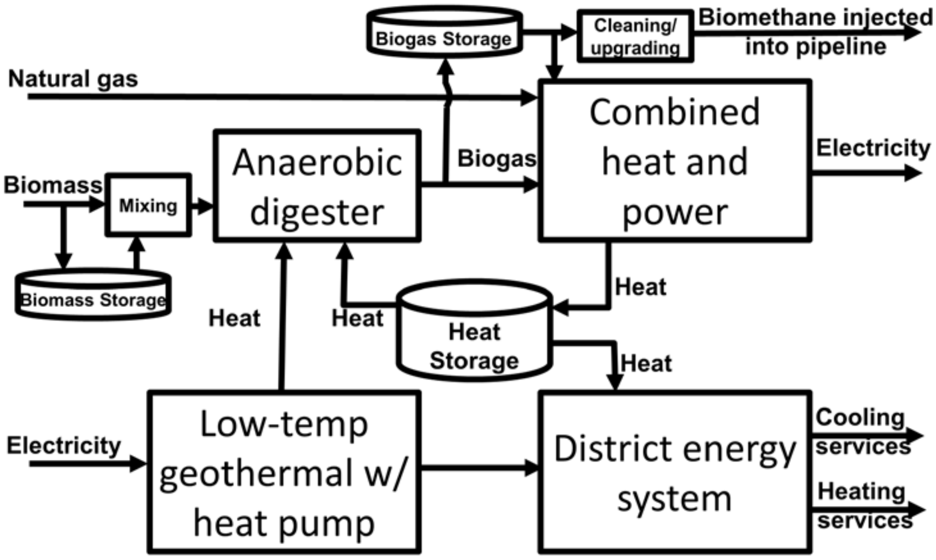


Figure 6: Advanced HES design based on anaerobic digestion (3 inputs and 3 output)

An advanced HES can be conceived around an AD. As illustrated in Figure 6, such a HES has three energy inputs (natural gas, biomass, and electricity), three energy output services (biomethane, electricity, and cooling/heating), and three storage devices (biomass, heat, and biogas). Additionally, it also contains two heat sources: the combined heat and power (CHP) unit and the low-temperature geothermal system with heat pump (HP). The CHP and the HP serve both the AD and the district energy system. ADs utilize low-grade heat to support the digestion of organic materials (e.g., wasted food, plant clippings, animal manure, sewage) to produce biogas. The biogas can be used directly to fuel the CHP, it can be stored, or it can be cleaned and upgraded before injecting into a natural gas pipeline system. The district energy system distributes heat obtained from the CHP and HP systems to the demand; it could also provide cooling, if an absorption chiller is included.

The heat storage (or accumulator) facility and the HP provide that the HES meets heating and cooling demand while the CHP meets the flexibility requirements from the electricity system; alternatively, or in addition to, the heating demand may be controlled, reducing the need for the HP or the heat storage..

The integration of the AD in this HES is motivated in four ways:

- First, although ADs require heat, the necessary heat is low-grade ranging from 30-38°C, which can be extracted from a wide range of processes including HPs and CHPs. This sets AD apart, in comparison to processing biomass via gasification or pyrolysis, as these latter two methods require high-quality heat.
- Second, many attractive regions for wind energy development, for example in the US the Midwestern north-south “belt” (from about Wyoming on the western side to Illinois on the eastern side), are also a highly agricultural region with a diversity of biomass feedstock including animal waste, grass and maize silage, and grains (e.g., wheat, triticale). Thus, as wind and solar penetrations grow these regions, so will the need for flexibility, a need that could be met by HES through a biomass resource indigenous to the region. Although there are over 11 000 AD facilities in Europe and 2 100 in the United States, the potential for agricultural biomass digestion remains underutilised.

The majority of the US facilities, about 1 880 of them, are associated with wastewater treatment plants or landfill gas projects; only 247 of them are on farms and thus making use of agricultural biomass.

- Third, if the input feedstock would decompose naturally, undergoing the same biological process as in the AD, then it would emit methane directly into the atmosphere. Considering that the global warming potential of methane is at least 21 times higher than the CO_2 released if the AD is used, then AD operation can represent a significant reduction of greenhouse gas emissions.
- Finally, investment in AD provides an effective hedge against long-term natural gas price volatility, a manifestation of the economic flexibility of the HES.

Another HES example are hybrid heat pump- gas boilers that use both gas and electricity to supply residential heat. Smart integration of such heaters enables to shift in real-time between the different fuels to respond to system conditions. For example, the hybrid heaters have the ability to switch from gas to electricity for generating heat at times of excess renewable electricity on the power grid and - vice versa - at times of peak electricity demand, they have the ability to switch from electricity to gas. The wide-scale deployment minimises electricity capacity expansion compared to single-fuel heat pump deployment and reduces upfront cost for consumers since the expansive heat pump can be downscaled. Their deployment also supports decarbonisation and reduces natural gas dependency compared to single-fuel gas boilers. The technical flexibility is limited by the consumer comfort, which depends on personal preferences as well as on building properties. An investment study for Ireland of this technology indicates that the deployment of this technology is cost-effective and enables system-wide cost reductions compared to boiler and HP-only deployment.

A third HES example is based around electrolysers, which are fuelled by electricity and produce synthetic natural gas and hydrogen. These outputs can be stored locally, fed into the gas grid or used as feedstock for industrial processes. Excess wind energy that would otherwise be curtailed can be used to run an electrolyser and produce hydrogen. This HES enables to further integrate the electricity and natural gas system. The resulting hydrogen can be used as transportation fuel or industry feedstock. Alternatively the hydrogen can be fed directly into the gas system or processed to synthetic natural gas. The admissible hydrogen concentration for direct injection into the gas grid is limited mainly by gas combustion equipment, due to the different combustion properties of hydrogen leading to flame speeds and reactivity, and hydrogen embrittlement of the pipeline. This HES enables storage of excess renewable electricity in a gaseous fuel, thus providing access to the vast storage capabilities of the gas infrastructure. The gas network offers storage capabilities over all time frames, from daily cycling as line-pack to inter-seasonal storage in underground storages, and is thus much more flexible than other storage technologies. This HES provides therefore a vast amount of operational flexibility, but its economic potential largely depends on the price spread between wind energy and the hydrogen price, as well as between hydrogen and natural gas. Also the electrolyser cost itself make the deployment today prohibitive. A few pilot plants have been built since 2013 in Germany with support of both industry and government. The Danish system operator expects to rely on electrolyzer systems by 2030 to provide flexibility.

4.2. Benefits of wide-scale HES deployment

The economic flexibility resulting from wide-scale HES deployment manifests itself by an increase in resilience. An indication of resilience of a certain system is typically the total price increase of electric and natural gas services nation- or continent-wide after a disturbance or disruption. A lower price increase indicates a higher level of resilience. As indicated in Figure 7, HES deployment increases the link-density of the overall networked system delivering energy from raw resource to the service demands relative to single-input-single-output power plant designs. HES provides increased path redundancy between energy resources and energy services, offering alternative means to satisfy energy service demands. After the Katrina/Rita Hurricanes of 2005 in the Gulf of Mexico, a large percentage of the US natural gas supply was shut-down for many weeks. Although electric and natural gas demand was interrupted only for a short time in a localized region, electric and natural gas prices rose steeply throughout the nation, and they did not return to their pre-hurricane levels for months. An increased link-density due to HES deployment would have enabled shifting between supplies and products after the natural disaster occurred, thus minimising the price spike.

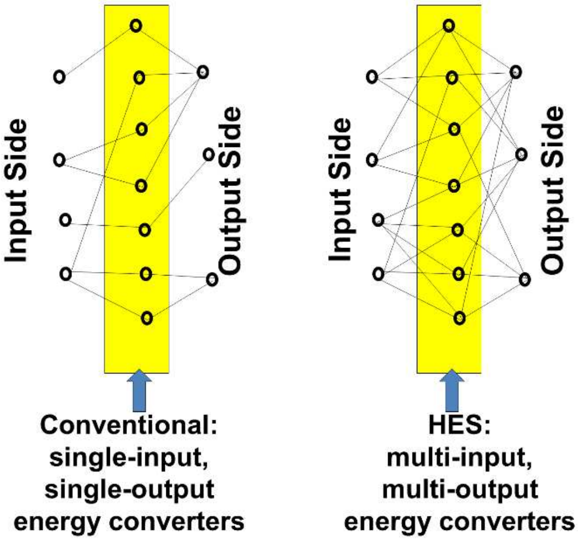


Figure 7: HES impact on network link density

HES plants are scalable from conventional utility-sized generation to distributed resources (DR) to meet flexibility needs at different scales. DRs are connected at the electric distribution level (consistent with IEEE Standard 1547), which means that for some small-scale applications the capacity is constrained by distribution circuits. Distributed HES plants with capacities of 10-100MW however could be connected directly to the distribution substation rather than distribution circuit, which means that their DR potential is less limited. Distribution substation connections of resources at this capacity maintain partial benefit of proximity to loads while still retaining the ability to utilize the transmission system without reversing flows on distribution circuits. Therefore, wide deployment throughout a region of many HES of this scale will result in satisfying operational flexibility necessary for high wind and solar penetration, enabling economic flexibility, and balancing benefits of load proximity with transmission accessibility.

HES deployment can potentially provide both operational and economic flexibility by combining different energy resources – inputs - and energy services - outputs. However, the industry is often disaggregated and many plant users are only active in one specific market. Therefore, plant owners and companies may not see opportunity arising from a bi-product, may lack the skills to expand to new markets or they may shy away from the risk to expand into unknown markets. Collaboration and research are essential to develop skills and confidence.

5. Conclusion

Gas turbines are today the main flexibility source, next to interconnectors, to balance demand and variable supply and meet demand for stable grid operation. Gas-fuelled power plants typically start-up quickly and provide excellent ramping capabilities that cannot be understated. Profitability of gas power plants is decreasing though since operational hours are dropping and material wear-and-tear is increasing. Gas turbine R&D efforts is focussing on reducing cycling costs and maximising flexibility capabilities, but market design that rewards flexibility adequately is essential to ensure system reliability.

The cyclic operation of gas power plants increases gas supply variability and requires increased use of short-term storage and intra-day market trading. Increased coordination between gas and electricity infrastructure is critical due to the different time constants for real-time operation of gas and electricity networks.

Further integrating energy resources and energy services through HES can increase both operational and economic flexibility of an energy system. A variety of HES designs are possible that enable to make use of existing infrastructures and meet local demands. Additionally, the deployment of HES plants improves system reliability and resilience by increasing the link-density and enabling to switch between different supply sources and products. However, collaboration between sectors and industries are essential to realise this potential.

The gas infrastructure is a major flexibility resource for the electricity system. A holistic perspective including both systems captures couplings and interactions and, if those are significant, then it reveals integration challenges and opportunities to further increase the flexibility options

Recommended reading list

COWI and DNV KEMA 2012. Study on Synergies between Electricity and Gas Balancing Markets (EGEBS). Brussels. October 2012

Federal Energy Regulatory Commission and North American Electric Reliability Corporation. Report on Outages and Curtailments During the Southwest Cold Weather Event of February 1-5, 2011 - Causes and Recommendations. August 2011

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