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Perspectives on the Utilities Industry 2017

Arthur D Little

Content

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Foreword

Dr. Jaap Kalkman
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Dear Reader,

The energy industry, from oil and gas to utilities, is going through an unprecedented change. It's a change similar to when the world moved from wood to coal, with the steam machine, or from coal to oil, when utilities centralized and the car industry took off early last century. Today, the shift is from hydrocarbons to alternative and renewable sources of energy. The change will be gradual from our perspective, but could be completed this century.

Historically, this is a revolution. It has huge implications on our businesses, on the way we organize and on the way we focus, from the R&D agenda to new business development focus and M&A. ADL's Energy & Utility Practice works in the center of that change, and aspires to be your advisor and business counsellor of choice. To that end, we continuously conduct research and push the envelope with new thinking and drawing implications of the trends we see around us. We trust you will enjoy the reading, and are, of course, open to comments and discussion.

You know where to find us!

Warm regards,

Dr. Jaap Kalkman

Arthur D Little

America First: carbon emissions go last?

Potential impact of President Trump's "America First Energy Plan" on the power sector

The Trump administration's approach to the traditional energy trilemma (the challenge of balancing the goals of cheap, secure and clean energy) appears set to skew heavily towards the low cost and secure aspects of energy supply at the expense of any focus on carbon emissions. While federal legislation, such as the Clean Power Plan (CPP), and U.S. commitment to the Paris Agreement (COP-21) may fall casualty to anticipated policy actions, our analysis shows the future for carbon emissions will not be as gloomy as many fear – largely due to the trajectory the power sector is already firmly on.

Decarbonization: a policy of the past in the U.S.?

The December 2015 Paris Agreement was seen as a landmark for decarbonization: policy makers the world over, including the chief emitters, China and the U.S., agreed a deal to strengthen the worldwide response to climate change. To date, 127 out of 197 Parties have ratified the Agreement.

The Obama Administration approved the Paris deal in September 2016. The U.S. target for greenhouse gas emission reductions currently stands at 26 to 28% below 2005 levels by 2025. The main federal energy policy measure to deliver this decrease in carbon was Obama's Clean Power Plan (CPP), which sought to reduce emissions from the power sector by 30% by 2030.

With the Trump Administration now in the White House, the CPP is unlikely to be implemented. U.S. energy policy will be replaced with the "America First Energy Plan". It may only be a high-level summary at this stage (March 2017), but the focus has clearly shifted away from low carbon; the emphasis is now on low cost supply and utilizing domestic energy sources, specifically coal, shale oil and shale gas.

There is no doubt that there is an abundance of coal, oil and gas in the U.S. Unconventional production methods have been a game-changer, and technology improvements continue to reduce the cost of extraction. Renewable power can also be a cost-competitive energy source, and an additional provider of domestic energy supply and potential economic growth (a view supported by energy giants such as Shell, which recently reiterated its intention to invest beyond fossil fuels). But there is no clear mention of either increasing renewable generation capacity or in limiting greenhouse gas emissions in the current version of the Plan (although clean air and water are included). Trump's new policies, despite calls from the E.U. and China not to abandon the decarbonization goal, seem to be a major shift in recent U.S. policy, and a potential U-turn away from the initial commitment on climate change.

In this Viewpoint, we consider whether significant reductions in carbon emissions can still be achieved if Obama's Clean Power Plan is disregarded, and then under a possible Trump "America First Energy Plan" scenario. In essence, what happens to U.S. emissions in the power sector without continued support for renewables? Will natural gas, the cleanest of the fossil fuels, compete against coal to continue to deliver a reduction in U.S. greenhouse gas emissions?

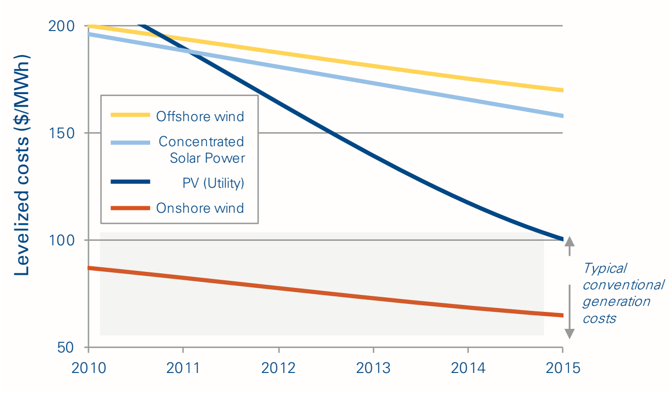
Major progress towards the "renewables plus natural gas" model has already been made

We continue to believe that a higher renewables world, supported by natural gas, remains a plausible low cost, low carbon, secure energy future for the U.S.

Renewable energy sources have out-performed all expectations – in terms of costs...

The cost of renewables has dropped far faster than anyone expected, e.g. by over 70% in the last 5 years for solar PV, and by 15-25% for onshore and offshore wind. PV and onshore wind are now competitive with conventional power sources in many areas of the U.S. (on a levelized cost basis, and without subsidy) and costs continue to reduce.

Figure 1. Recent evolution of selected renewable technologies (excluding tax credits and subsidies)



Source: EIA, NREL, IRENA, Arthur D. Little

...in terms of capacity

The Energy Information Administration (EIA), and other institutions, have historically hugely underestimated the growth of solar PV and wind, particularly PV. For example, the 2011 Annual Energy Outlook (AEO) projected a 2035 PV installed capacity level which had already been exceeded by 2013. The latest AEO reports have significantly upgraded the renewables growth forecast, with capacity now expected to double by 2040, though these figures still look conservative based on recent developments in an industry where installed capacity increased by 30% in the last five years.

...and in terms of grid integration issues

A fear often highlighted for large scale integration of renewables is the need for substantial quantities of spinning reserve as "back-up" to maintain system balance. There are additional costs from maintaining reserve plant and/or storage, plus the extra network reinforcement costs to cope with fluctuations in supply from more widely dispersed renewable generation assets.

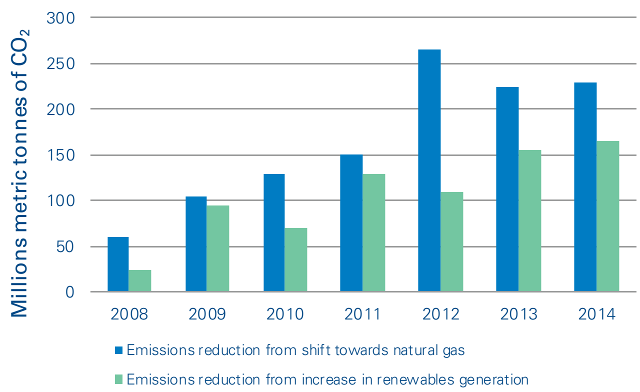
Our review suggests that the total back-up capacity required is relatively modest, at around 5% for 33% renewables penetration, and could be around 10% for 50% penetration. This back-up capacity can be provided by a mix of peaking plant, storage and demand-side response.

Natural gas has driven recent U.S. emissions reductions, despite the growth in renewables

Natural gas contains less carbon per energy unit than coal, and the power production process is itself more efficient; emissions of CO2 per TWh of electricity produced using natural gas are less than half those from coal.

The abundance of low cost natural gas has already played a substantial part in the efforts to reduce greenhouse gas emissions in the U.S., mainly via the replacement of older coal-fired power stations. The emissions impact of coal switching to natural gas in the power sector outweighs the impact of renewables to date.

Figure 2. Historical emission reductions from natural gas and renewables



Source: EIA

Despite recent decreases in installed capacity and output, coal-fired generation remains a major component in the mix, leaving significant headroom for coal replacement by natural gas and further emissions reductions.

Natural gas turbines also combine relatively low cost, high capacities, and high ramp rate capability, giving them the flexibility to complement renewables. They therefore play a critical role in enabling faster renewables growth.

Our scenario analysis shows emissions continue to reduce

EIA base scenarios

The EIA publishes an annual, detailed forecast of the energy sector in the U.S. In its Annual Energy Outlook 2017, it shows the impact of the Clean Power Plan on emissions. Figure 3 below shows the emissions forecasts for the power generation sector, for various scenarios.

The top of the red shaded area shows the EIA's most recent forecast of power sector emissions, assuming no CPP. The top of the blue shaded area shows the same forecast assuming the CPP continues.

In the early years, the EIA shows some uncertainty as to how quickly carbon emissions will fall, dependent on whether there is more or less switching to natural gas, whether oil prices increase or remain at current levels, and their subsequent impact on economic growth. This is represented in the chart below by the overlapping blue and red shaded areas from 2015 to 2025.

According to the EIA's estimates, emissions under the CPP are 17% lower in 2030 compared with the no-CPP case, or down 39% on 2005 levels. This is substantially higher than the CPP target of a 30% reduction on 2005 levels.

A "Deep Decarbonization" scenario

To demonstrate the potential for further emissions reductions from the power sector in the U.S. if focused political will were deployed (including the relevant subsidies, tax breaks, regulations and R&D support) we have constructed a low carbon scenario based on the EIA's data.

In this scenario, large, high emission, centralized coal plant would be rare, and instead, the power network would consist of an array of smaller, more efficient and highly distributed generation assets. Solar PV panels and wind turbines would be commonplace and storage technologies, at all scales, widely deployed. Renewables penetration would be 44% by 2035. Demand side management, energy efficiency measures and smart grid deployment would also continue to grow.

Crucially, in the background of any low carbon scenario, supporting the growth of renewables, would be fast-ramping gas turbines (OCGT or CCGT or a mix) supplying both a large percentage of centrally produced power, and playing a critical role in stabilizing the grid and balancing fluctuations in renewable power output. Optimization and aggregation of the assets available to the system would become key, in place of centralized dispatch.

The results of our "Deep Decarbonization" scenario are shown by the lowest blue line in Figure 3. Our analysis suggests that 2030 emissions could be a further 36% below the CPP case (or over 60% less than 2005 emission levels), representing a substantial shift towards a low carbon future in the U.S. power sector.

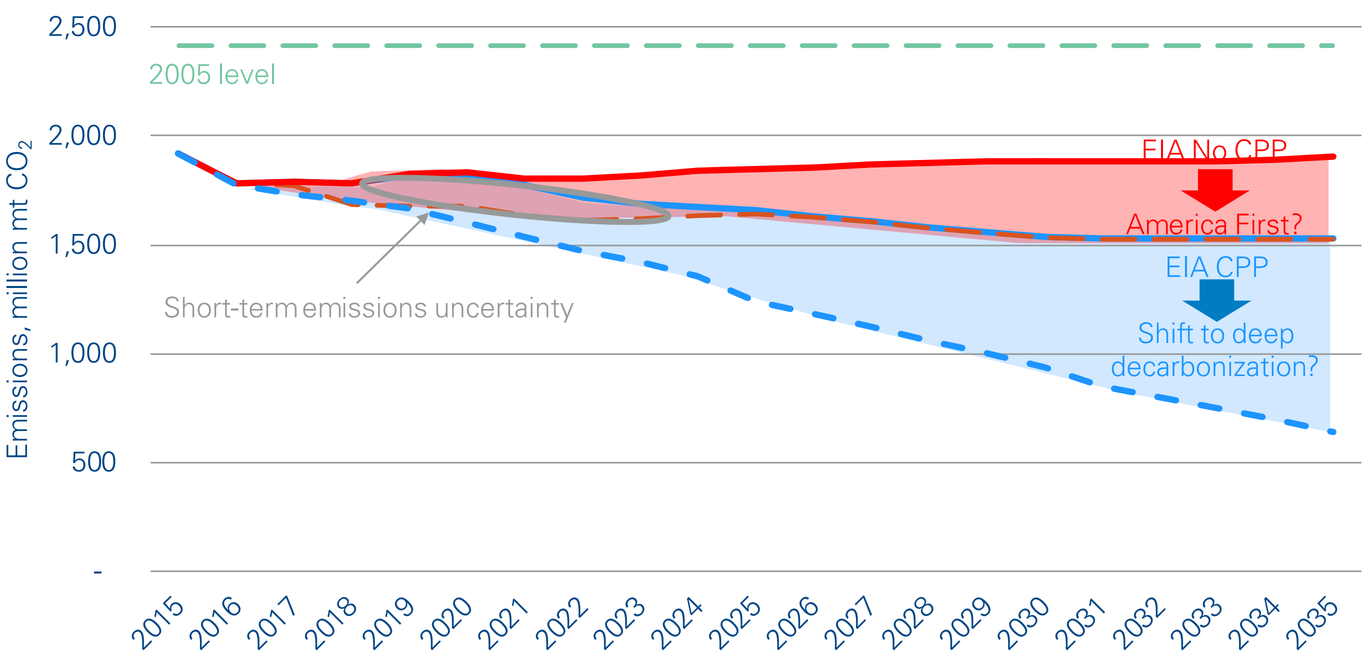
"America First Energy Plan" scenarios

Despite the significant potential to reduce emissions in the power sector, the only indication that the America First Energy Plan will consider carbon emissions in future policy is the mention of clean coal technologies, which for cost and fuel efficiency grounds have mostly failed to progress beyond pilot projects in the last decades.

Yet our analysis suggests that significant emissions reductions can occur in any event, due to a combination of factors:

1. **Previous government policy has already set the wheels in motion:** renewables were promoted, capacity has been built, infrastructure has been strengthened, more projects are under development, and costs have fallen. At least in the short term, it is hard to see how the trajectory will stall.

Figure 3. Emissions in the U.S. power sector, with and without the CPP



Source: EIA Annual Energy Outlook 2017, Arthur D. Little

2. **State-level policies may continue to promote renewables**, even if the CPP and federal level support is removed. For example, California passed law SB-32 in 2016, which aims to reduce carbon emissions to 40% below 1990 levels by 2030. As the world's sixth largest economy, Californian policy will have a notable effect on U.S. emissions.
3. **Natural gas will continue to displace coal.** Natural gas is the critical enabler of the low carbon economy, at least in the mid-term. And the shale gas revolution means there will be plenty of low cost gas in North America for the next few decades, even if significant volumes of gas are exported.

In Figure 3, the lower red line represents a possible "America First" emissions forecast for the power generation sector. In this scenario, we have assumed that renewables growth stalls post 2020, nuclear capacity remains stable, and natural gas continues to displace coal over the next 20 years. We have also assumed that electricity demand is equal to the EIA reference case. Using these assumptions, we forecast 2030 carbon emissions to be 13% below the no-CPP case (or 36% below 2005 levels). This is perhaps an optimistic case, with reality likely somewhere within the red shaded area in the chart, but it illustrates the clear potential to reduce emissions.

With reduced regulation, the market decides

As President Trump's energy policy is fleshed out further scenarios will emerge. Currently it appears likely that support for renewables will end, and fossil fuels will have to compete amongst themselves on a level playing field.

The logical outcome, with all energy sources competing on an economic basis, is that in the short-term coal and gas take turns as the cheapest power source on the basis of price fluctuations in each fuel, with regional variations. Choices for new investment, as they look over the longer-term, will be focused on natural gas and renewables, given that the LCOE for coal with carbon capture is double that of gas-fired combined cycle, solar PV and onshore wind.

The Trump administration will most likely reduce federal level support for decarbonization of the power sector. Despite this, our analysis suggests that carbon emissions will continue to reduce, suggesting that an economic tipping point in favor of low carbon technologies has already been reached.

Authors

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Battery storage: still too early?

A report by Arthur D. Little

Executive summary

Renewable energy deployment over the last decades has posed unprecedented challenges for the planning and operation of power systems. In the context of increasingly decentralized and intermittent generation, power utilities[1] and system operators need to rethink their portfolios, business models and positions in the market in order to be resilient to these changes and benefit from them.

Battery storage has gained strong interest as an option to respond to these new challenges and provide flexibility to the system to cope with high levels of renewables. Driven by increased usage in the automotive industry, costs of batteries have significantly dropped since 2010 (65% decrease for lithium-ion batteries[2]), although further cost reductions are necessary for widespread use in the power sector.

Actors all along the energy value chain find themselves facing a number of key questions when considering how energy storage may affect their businesses:

- In what applications will battery storage play a key role in managing the future grid?
- What will be the most attractive business models? For which (combination of) actor(s) along the value chain?
- What factors influence the choice of battery technologies?
- Which battery technologies will likely be the most important in each application?
- What are the drivers, enablers and alternatives to battery storage deployment?

In this report we respond to the above questions and describe the results of a study in which we have reviewed battery applications, battery types, drivers & barriers to battery storage and trends in key markets, based on interviews with major market players in the energy sector. We have explicitly addressed what's in it for the different types of stakeholders along the value chain. The key conclusions of our study are summarized below:

Deployment of stand-alone batteries to provide grid services such as frequency response and frequency regulation has mainly been achieved under pilot projects. Widespread deployment has been hindered by high costs and regulation uncertainty, but grid-scale storage for **frequency regulation**[3] is still seen as one of the most promising applications to date. Large-scale hybrid battery configurations, to **stabilise renewables output**, are also considered one of the biggest successes of batteries so far, especially on islands. Finally, **hybrid residential battery** configurations have seen a significant boost in some markets, such as Germany, where incentives are put in place.

1 For the purpose of this study the term "power utilities" includes generators (i.e. IPPs) and vertically integrated utilities (involved in generation, trading and retail), and excludes system operators, which are considered separate categories.
2 Bloomberg New Energy Finance, 2016.
3 Equivalent of FCR in ENTSOE terminology

DSOs and TSOs can use batteries for grid-support applications such as congestion avoidance, frequency regulation, frequency response[4] and voltage stability, and tend to see co-ownership as the most likely option for making a positive business case. Indeed, all market players generally see the **combination of several applications** as essential to make battery solutions economically viable. However, system operators are only likely to make major moves when the regulatory framework for ownership and operation of storage technologies has been further clarified.

Compared to system operators, power utilities are able to leverage batteries for a wider range of applications and less constrained by regulation. They can potentially use batteries to generate revenues from arbitrage in the market, decrease exposure to imbalance costs and provide grid services to system operators. Vertically Integrated Utilities (VIUs)[5] can also deploy batteries as part of their offerings to end customers, as is already seen in Germany, for example.

Aggregators are also major enablers of battery deployment today. Partnerships between VIUs and aggregators as well as battery manufacturers/system integrators and aggregators have been developed over the last few years to generate revenues primarily from ancillary services and the wholesale market with batteries at residential, commercial and industrial levels. The roles of aggregators continue to evolve, and the emergence of aggregators acting as software providers rather than technology operators is reshaping the position of VIUs in the market.

In conclusion while battery storage remains a market for early adopters today, with more mature business models for some players (e.g. power utilities) than others (e.g. system operators), time for inaction is far over.

Because whenever the technology shall be cheap, it will belong to those who invested in its development. And whenever the regulation will be more facilitating, the opportunities will be captured by those who have a business model ready.

This is the moment for markets to be shaped, lobbying to be done, regulators to engage with and early strategic actions to be performed for actors along the energy value chain to make sure they will be part of the future framework and at the forefront of market trends.

Contributions

Our additional thanks for contributions from Eirgrid and other network operators as well as from multiple storage technology providers

4 Equivalent of FRR in ENTSOE terminology
5 Power utilities involved in several steps of the supply chain, including generation, trading and retail (e.g. Engie, E.ON).

1. Batteries to support the energy transition

The power grid is in the midst of unprecedented change. Large amounts of renewables are being added to the grid in many parts of the world, coal and nuclear generation are increasingly disfavored, and there is a shift from the old centralized model of generation, transmission, and distribution to a more dynamic grid incorporating diversity of generation assets on a range of scales.

While generally positive from an environmental perspective, such changes present a number of challenges to grid operation, particularly for managing the integration of intermittent renewable generation technologies such as solar PV and wind. Among multiple solutions[6], energy storage will likely play a critical role in managing such challenges, for example, by smoothing the output from renewable sources and storing energy in times of high generation for later release when demand is strong.

Due to their flexibility, applicability on wide scale, and potential synergies with other applications such as electric vehicles, **electrochemical storage technologies** have received particular attention in recent years.

While battery storage remains marginal (less than 1 GW) today[7], the announcements of several large-scale commercial projects and some major transactions over the last year are clear signs that the sector is taking off.

Several models have emerged in which existing and new players in the power sector deploy and operate batteries to respond to the new challenges. Progress on both the technology and regulation fronts are necessary to clear uncertainties as to whether batteries are economically sound, and for whom.

This paper analyzes how battery storage can respond to the energy transition and addresses:

1. The applications of batteries and business models across the value chain;
2. Subcategories of electrochemical batteries, their characteristics, costs and specific fields of application;
3. The drivers for battery deployment and diagnostics in key country archetypes.

Recent major transactions and alliances in the battery storage sector

6 Interconnection, Demand Side Management, flexible generation
7 Bloomberg New Energy Finance

2. A business for all, except for system operators?

Batteries can be used at different **levels of the electricity system** and in **various applications**, from providing grid-support services to generating revenues from price spread in wholesale markets.

The main types of applications are briefly detailed below:

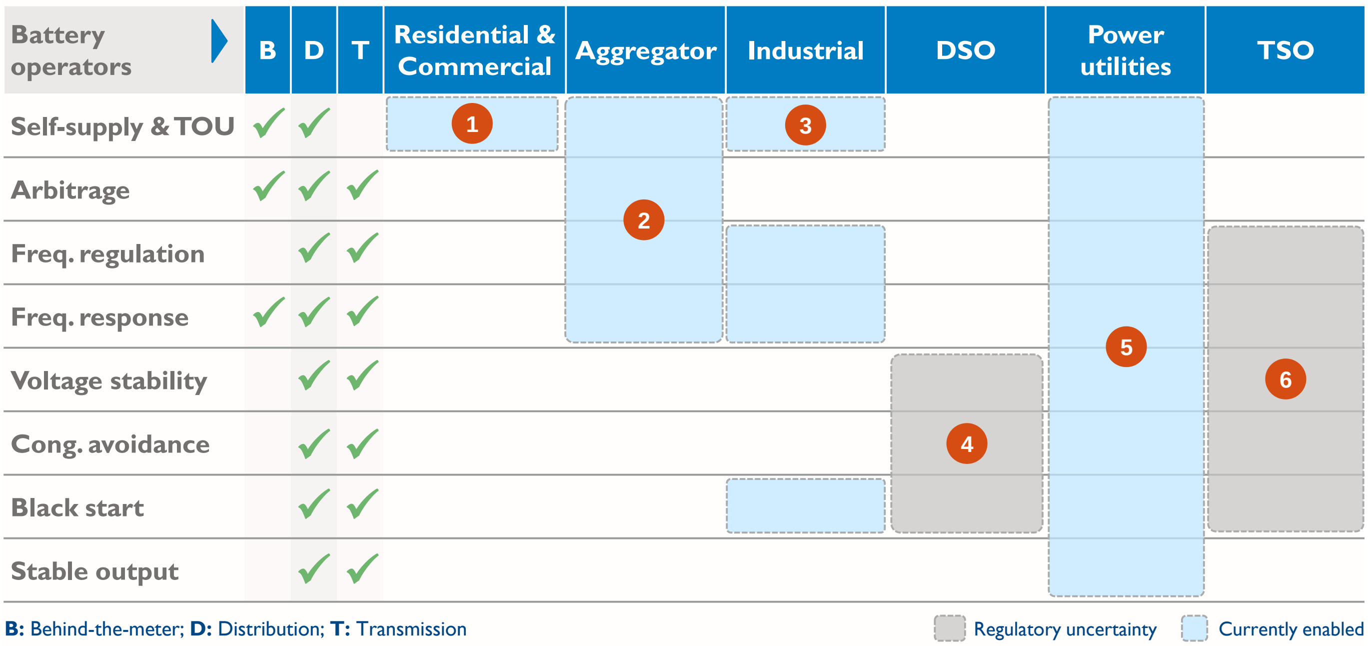
Terms[8]	Description
Self-supply & TOU	▪ Combined physically (hybrid systems) or virtually with distributed renewable sources, distributed storage behind the meter or on the distribution network allows at least partial self-sufficiency, resulting in decreased costs for grid supply and reduced exposure to price fluctuations. Savings could also be achieved by optimizing consumption based on time of use (TOU) and related price profiles ▪ Stand-alone, they improve reliability and power quality to end users in markets with poor security of supply or access to power supply
Arbitrage	▪ Batteries potentially located at any level on the grid (distribution, transmission or behind the meter aggregated as a virtual asset) are used to exploit the wholesale electricity price spread and charge during off-peak periods while discharging in peak periods (peak shaving) *Note that Time Of Use (TOU) included in the above application is also a form of arbitrage but operated by end-users (residentials, industrials).*
Frequency regulation[9]	▪ Under normal operating conditions, continuous charge and discharge of batteries located at distribution or transmission can maintain demand and supply in balance and keep frequency within required limits
Frequency response[10]	▪ Under contingency conditions, when system failure leads to major and sudden frequency variation, batteries are activated to restore primary control ▪ Batteries at distribution, transmission or behind the meter are aggregated as virtual assets
Voltage stability	▪ Batteries, at specific locations in the distribution and transmission network, release or absorb reactive power to maintain power quality locally
Congestion avoidance	▪ Charge and discharge of batteries, at specific locations in the distribution and transmission network, enable postponing investments, remaining compliant during works on the network, and increasing renewable penetration where the limits of the grid are reached in order to avoid congestion at substations during local peak periods
Black start	▪ Batteries, at specific locations in the distribution and transmission network, are used to energize pieces of the network when there is a black-out
Stable output	▪ Batteries at distribution or transmission level, combined with intermittent renewables (e.g. wind, solar) enable the generator to smooth output to comply with regulatory duties or mitigate imbalance

The majority of the above applications can be stacked, allowing the operator/owner of the battery to capture the value across several services. For example, a wind-farm operator would install a battery to stabilize its output and limit imbalance costs while also capturing revenues through the provision of ancillary services[11].

Figure 1 maps stakeholders across the value chain to the potential applications they will address when operating batteries.

8 Ancillary services/operating reserves required by TSOs/DNOs have been classified into frequency regulation, frequency response, voltage stability and black start. Planned/ strategic reserves (e.g. capacity mechanism) are considered as a way for batteries when operated under a specific application to capture additional revenues.
9 Equivalent of FCR in ENTSOE terminology
10 Equivalent of FFR in ENTSOE terminology
11 Services identified as necessary by the transmission or distribution system operator to enable them to maintain the integrity, stability and power quality of the transmission or distribution grid

Figure 1: Mapping of battery operators & key applications



1 Equivalent of FCR in ENTSOE terminology
2 Equivalent of FRR in ENTSOE terminology

Power utilities, and in particular vertically integrated utilities (VIUs)[12], are the only players in a position to address all major applications, from providing support to the grid to maximizing revenues from the wholesale market and operating batteries to optimize consumption. However, their ability to stack these applications strongly depends on the accessibility and definition of these services and the extent to which they are mutually exclusive.

The same application often sees several competing models across the value chain (R&D, development, ownership, operation and maintenance) able to provide the services and possible structures or business models are discussed below:

Residential & commercial

Three main reasons can lead the residential & commercial sector to operate batteries:

- **Poor security of supply**, with frequent outages: battery is an emergency back-up if an outage occurs. However, the business case remains challenging and depends on the value of stable supply and loss load, which is especially hard to assess at residential level.
- **Poor access to the main grid** and the possibility, with battery storage combined with distributed generation, of remaining off-grid. Battery storage is, for example, installed in telecom towers and responds to the needs of telecommunication networks willing to expand to the remotest places in the world and provide uninterrupted supply. The telecom sector is the leading market for commercial use of battery storage so far and, as such, the market is expected to grow at 10% over the next five years[13] in key markets such as India and Africa.
- Desire to become more **self-sufficient and reduce electricity costs** by combining storage and distributed generation (e.g. PV panels) and increase self-production.

OEMs and system integrators[14] such as Tesla sell directly to end users or through the intermediary of official suppliers[15], which install the technology at the end user's premises. End users, in turn, operate and own or potentially lease[16] the devices. A leasing business model for residential batteries can be particularly interesting in facilitating the combination of storage applications that span multiple stakeholders. In Germany, for example, residential hybrid PV/battery systems are mainly used to increase self-consumption during summer months, and the batteries' state of charge is near zero during the first three months of the year. This means system operators could potentially use residential batteries for grid-support applications during this period. Such a business model could be

12 Power utilities involved in several steps of the supply chain, including generation, trading and retail (e.g. Engie, EON)
13 *Economic Times*, March 2016
14 System integrators are responsible for packaging the batteries and adding auxiliaries such as control systems
15 VIUs or distributors of battery solutions
16 The leasing model is quite common for solar PV and CHP

facilitated through a leasing contract, and enables residential and commercial customers to benefit from the use of batteries for other applications and improve the business case.

Other business models have been developed to leverage batteries owned by residential and commercial customers to capture price spread and/or ancillary revenues via aggregators and VIUs. These models are discussed below.

Aggregators

The aggregator role has developed to fill the gap left by increasingly distributed generation that is unable to participate in the energy and ancillary services market. Aggregators effectively aggregate a large number of generation and demand sources into controllable power plants referred to as virtual power plants (VPPs).

The German, French, Belgian and UK markets have been incubating virtual power plants for five years now. VPPs have started to become viable, but this evolution will accelerate by decreasing battery cost and involvement of strong players in the market such as Tesla. In Germany, Tesla and Sonnenbatterie signed deals with VPP player Lichtblick to link residential batteries to the control platform last year. Savings can be passed on to customers in multiple ways (not comprehensive): through direct payment to the end customers when the aggregator is using the scheme or fixed yearly payment (preferred models so far); under a profit-sharing model; or upfront as a discount on the battery investment costs (with the challenges that it poses in terms of forecasting reserve-auction results).

The provision of ancillary services by aggregators is a proven model tested through demand-side response for years now. Electricity trading by aggregators for arbitrage, on the other hand, faces more hurdles because of the volume of imbalances it can cause for balance-responsible parties (BRPs)[17] prior to the settlement process.

Therefore, coordination between aggregators and BRPs is needed for aggregators to operate in a deregulated energy market (e.g. day-ahead or intraday). Aggregators have been working hand in hand with VIUs, which enable aggregators to not only overcome the balancing-responsibility issue mentioned above, but also channel their business propositions to end customers. However, as the market matures, we can observe a progressive split between aggregators willing to remain operators of flexibility in the system and those focusing more on selling the demand-response management software (e.g. AutoGrid Flex from Autogrid). This evolution might, in turn, fuel a shift for VIUs, which will reposition themselves in the market and offer these services without aggregators.

More specific to the commercial and industrial sectors, energy service providers (e.g. Dalkia, part of VIU EDF) have also acknowledged the potential of acting as aggregators. We can expect them to play an important role in leveraging additional value from battery storage building on their current client bases and further transform the aggregator landscape in the near future.

Industrials

Similar to the residential and commercial sector, industrials are likely to use batteries to cope with power-outage issues and become more self-sufficient, as well as avoid network charges where consumption is measured at certain times of the year. Industrials will either operate their battery storage themselves in the same way they participate in ancillary services or outsource the operation to power utilities or aggregators.

Depending on their size and the part of the network they are connected to, industrials could be partnering with DSOs and TSOs in order to optimize their consumption patterns while generating revenues from grid-support activities (e.g. voltage stability, black start). We see few applications of this business model to date, but it can be a particularly good alternative for system operators that have their hands tied regarding their roles in storage activities.

DSO

The integration of renewables poses a number of challenges for DSOs in terms of power quality and grid reinforcement to accommodate renewables at their maximum potential.

Batteries deployed in strategic locations of the network have the potential to relieve grid congestion and therefore avoid or postpone grid reinforcement. Battery storage, in this case, finds itself playing a role in the medium- and long-term operation and planning of the system. However, batteries today remain, in most markets, too expensive and do not present favorable economics relative to the critical time of use and/or alternative system-wide upgrades.

Another field of application for batteries is the provision of voltage control to improve the quality of supply, but this is likely to be only as part of a wider set of applications, given that it can be achieved through other, cheaper components of the network (e.g. stand-alone inverters).

In Europe, the unbundling of the sector has confined system operators (DSOs, TSOs) to owning and operating transmission and distribution assets only. It has not been clear so far whether some regulatory bodies consider battery storage a generation

17 Entities responsible for composing a balanced portfolio of generation and consumption

asset, but the European Commission (EC) recently proposed a definition for energy storage and the principles of its deployment (see box page 11.) This will hopefully mark the beginning of the end of a period of uncertainty regarding the exact roles that system operators can take with batteries. In the meantime, system operators are already considering innovative business models to deploy batteries without entering the energy market.

Examples of such business models are the deployment of batteries at complementary locations in the network (centralized and congested areas) in order to neutralize the charging and discharging effects and avoid interacting with wholesale markets to balance the network (Tennet, the Netherlands).

Regulatory uncertainty so far and challenging business cases explain why the track record of commercial battery deployment for distribution-grid applications remains poor today. While many pilots have been running in Europe and worldwide to test the technology and its performance for specific applications, actual commissioning of battery solutions for commercial grid applications is limited.

EDP (Portugal) is testing concrete applications of distributed energy storage and energy management in the distribution grid to demonstrate the relevance of storage for power-supply reliability and power quality in partnership with Siemens and the University of Evora. The project was commissioned in December 2015 and focuses on storage for rural/semi-urban grids as part of a wider program led by Siemens.

Potential business models will develop as regulation and costs evolve, but the general view among DSOs (EDP, Eandis) is that shared operation of batteries will be necessary for DSOs to build viable business cases while sticking to their areas of activities.

"Storage could become an asset in the grid to overcome local (extreme) congestion, and to protect the power quality and security of supply but only when techno-economically a better solution than the current alternatives. In that case and for that part DSO could be the owner of the storage but it is more likely that they would lease or use or (in what way possible) a part of a battery that was installed by a third party on the grid" (Eandis, Belgian DSO).

Power utilities[18]

Vertically Integrated Utilities (VIUs), being at the interface between end customers and system operators, have the potential to play a significant role in the battery market.

In their capacity as retailers, they act as enablers for deployment of residential battery storage. In adding battery storage as part of their energy services packages, VIUs aim at differentiating themselves and benefiting from extra revenue streams. Several VIUs in Germany are offering battery solutions to their customers. E.ON, for instance, released its home storage system combining PV, storage, app and tariff in April 2016.

In Benelux Eneco has been supplying the Tesla Powerwall to its customers since the start of 2016. A couple of months later it expanded its services to CrowdNett with the support of Tesla, SolarEdge and Ampard. The software developed by Ampard allows controlling residential batteries remotely so they can participate in the provision of ancillary services. In exchange for the use of 30% of the battery capacity, residential customers receive 450€ in compensation guaranteed over the next five years.

Beyond the retail side, battery storage represents a key opportunity for VIUs and generators to:

- Decrease exposure to imbalance charge from renewables intermittency
- Optimize asset production and sales in the wholesale market based on market signals (arbitrage)
- Capture revenues from ancillary services and capacity mechanisms
- Support industrial or consumer groups in avoiding system charges, where these are calculated based on consumption at peak periods, and negotiate to receive a portion of this saving

Among the above applications, the latter two are good entry points for new entrants, aggregators, energy traders and merchant players to generate revenues of battery storage under a more opportunistic approach than incumbents.

The possibility for power utilities to combine revenues from multiple applications improves the battery business case but depends on market design specifics (e.g. provision of multiple services to multiple parties at the same time).

An example of production optimization/arbitrage can already be seen on a large scale in the US, where we expect that within four years the world's biggest storage capacity project in Los Angeles will be delivering over 100MW for about four hours at peak period[19].

Finally, depending on local regulations, generators might have to comply with specific ramp-up and ramp-down profiles and

18 For the purpose of this study the term "power utilities" includes generators (i.e. IPPs) and vertically integrated utilities (involved in generation, trading and retail), and excludes system operators, which are considered separate categories

19 *Scientific American*, July 2016

therefore be obliged to couple intermittent generators with battery technologies on site. Islands are a good example of markets where such constraints have been put in place (e.g. Puerto Rico, La Réunion).

TSO

In the same way TSOs might contract with power utilities and large customers for ancillary services (frequency response, voltage control) and reserve (strategic reserve through capacity mechanisms), they could potentially meet their requirements by owning batteries.

However, similar to DSOs in Europe, the business models under which TSOs will be able to own and operate batteries remain to be defined in most countries. Market solutions are always preferred. The development and ownership of batteries by TSOs raise questions about market distortion and funding of regulated monopolies. But some players have highlighted the necessity, when market conditions are not appropriate and a solution is required, to implement storage through a regulated solution (Red Electrica and ENTSO-E[20], Terna).

In Italy the regulatory framework was adapted to allow for the TSO Terna to develop and operate batteries in the network. Two major pilots, respectively, of 40 MW in Sicily and Sardinia (power-intensive projects) and 35 MW in South Italy (energy-intensive projects) are being led by Terna in collaboration with universities and research companies to prove the applicability of batteries for system balancing, ancillary services, power quality and tertiary reserve. The technologies under consideration include lithium-ion, flow and sodium-sulphur batteries.

Again, transmission system operators such as National Grid and Tennet agree on the fact, to make the business case positive, multiple value streams and collaboration between different market players are required.

Because of their scalability and the multitude of applications they address, batteries can be owned and operated by many market players. Figure 2 shows the position of key market players across the value chain and potential business models.

Figure 2: Potential business models across the value chain

End Customers	R&D, manufacturing	Development & Integration	Ownership	Operation	Maintenance
1 Residentials & Commercials as battery operators	Battery OEM	System integrator/ battery distributor	R&C		System integrator/ battery distributors[I]
	Battery OEM	System integrator + Utility	Utility: leasing model	R&C + utility	Utilities[I]
	Battery OEM	System integrator + DSO	DSO: leasing model	R&C + DSO	System integrator[I]
2 Aggregators as battery operators	Battery OEM	System integrator	R&C	Aggregator	System integrator[I]
	Battery OEM	System integrator	Industrial	Aggregator	System integrator
3 Industrials as battery operators	Battery OEM	System integrator + utility	Industrial	Industrial + utility	System integrator
	Battery OEM	System integrator	Industrial		System integrator
4 DSOs as battery operators	Battery OEM	System integrator + DSO	Industrial	Industrial + DSO	System integrator
	Battery OEM	System integrator + DSO	DSO		System integrator
5 utilities as battery operators	Battery OEM	System integrator + utility	Utility		System integrator
	Battery OEM	System integrator + utility	Utility		
6 TSOs as battery operators	Battery OEM	System integrator + TSO	TSO		System integrator
	Battery OEM	System integrator + TSO	Industrial	Industrial + TSO	System integrator

Operator Structure to be developped pending regulation

I Few maintenance needed

20 Energy Storage, global conference – Brussels – 2016 regarding law adaptation for energy storage in Gran Canaria

The gap in the regulatory framework regarding batteries in markets such as Europe has slowed down development of clear strategies and business models by system operators, but positive signs have been seen recently (ENTSOE, Ofgem, the European Commission) to establish a clear framework and market mechanisms for batteries.

In an attempt to clarify the legislative framework in which batteries operate, the European Commission released the Electricity New Market Design Package in November 2016, providing clarifications on the role of system operators with respect to energy storage in their proposal for a revised electricity Directive. The EC states that *"Transmission system operators shall not be allowed to own, manage or operate energy storage facilities and shall not directly or indirectly control assets that provide ancillary services".*

However, under some conditions, TSOs could derogate from this obligation:

"(a) other parties, following an open and transparent tendering procedure, have not expressed their interest to own, control, manage or operate such facilities offering storage and/or non-frequency ancillary services to the transmission system operator;

(b) such facilities or non-frequency ancillary services are necessary for the transmission system operators to fulfil its obligations under this regulation for the efficient, reliable and secure operation of the transmission system and they are not used to sell electricity to the market; and

(c) the regulatory authority has assessed the necessity of such derogation taking into account the conditions under points (a) and (b) of this paragraph and has granted its approval."

In addition, the EC provides with a definition for energy storage as *"deferring an amount of the electricity that was generated to the moment of use, either as final energy or converted into another energy carrier".*

Despite those propositions, EASE (European Association for Storage of Energy) requests the EU to recognize energy storage as a separate asset class, alongside generation, transmission/distribution and consumption to avoid the unwarranted double charging (energy imported from the grid and exported to the grid, including levies and taxes) imposed to storage facilities, which does not reflect the value of storage to the grid.

"Power utilities, and in particular vertically integrated utilities, are the only players in a position to address all major applications, from providing support to the grid to maximizing revenues from the wholesale market and operating batteries to optimize consumption."

3. High synergies with other sectors will push Li-Ion batteries

For grid applications three critical parameters characterize the performance of electrochemical storage technologies and are the most important in the selection of a technology:

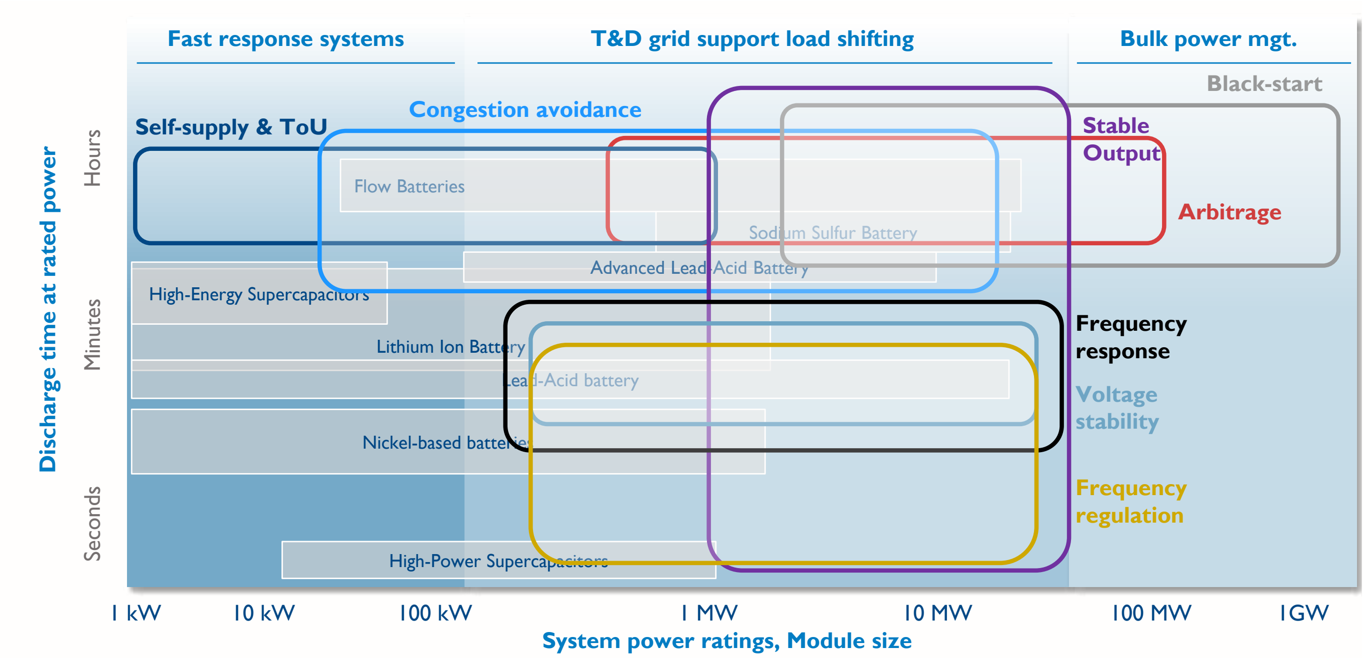
- **Response time** is how quickly a storage technology can be brought online and discharge energy
- **System power rating** is the maximum output available to address flexibility needs
- **Discharge duration at rated power** is how long a storage device can maintain output

Potential applications for a given technology will depend on the balance between these parameters. For example, technologies with high power capabilities and rapid response but short discharge times will lend themselves to applications such as frequency regulation, but will struggle with large-scale energy storage applications such as arbitrage. Conversely, technologies with very long discharge times but slow response times would be good for arbitrage or stabilizing output from renewables, but may not be suitable for applications such as frequency response, which require rapid changes in output. Figure 3 maps applications to power ratings and discharge times, and also indicates where some of the major technologies (see discussion below) are most applicable.

In addition to the main parameters, the following factors are important when considering an investment decision:

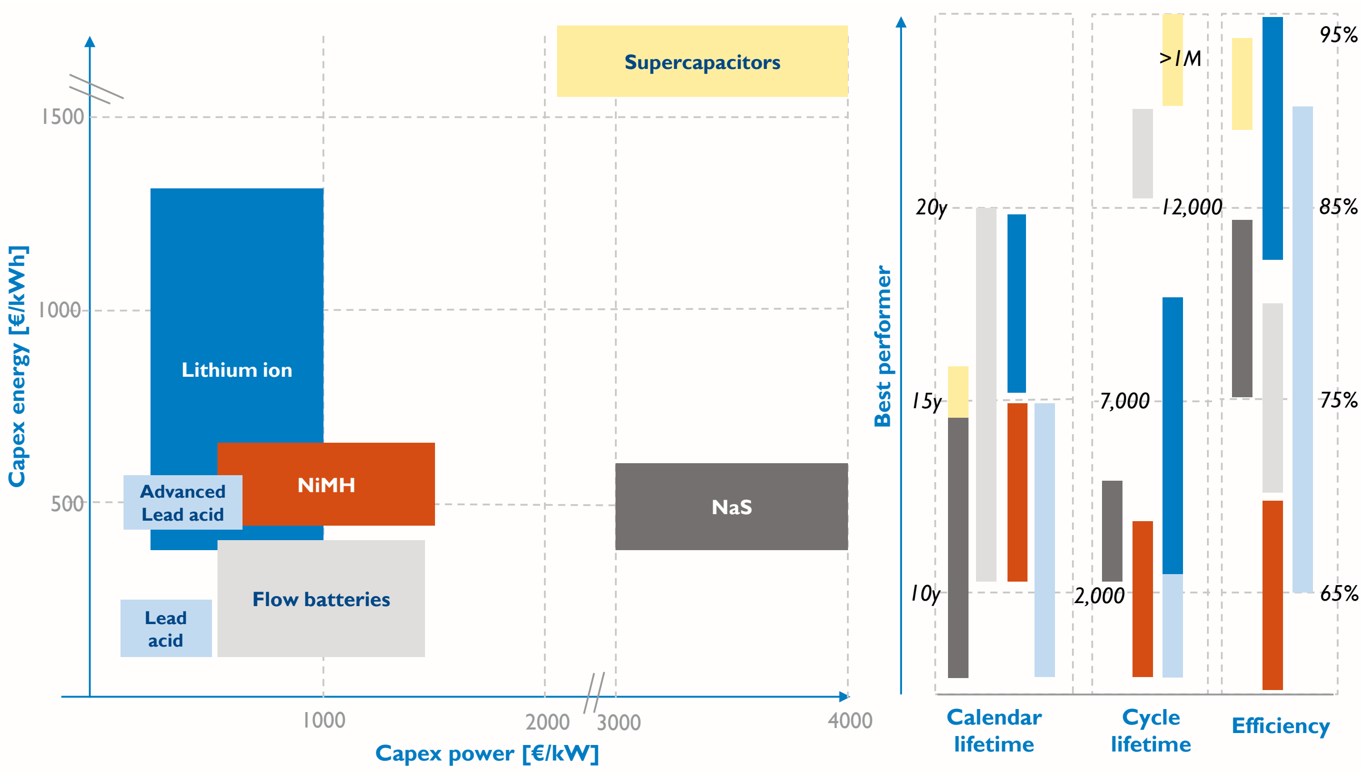
- **Reliability**, in terms of percentage of time that the capacity is available when needed. Utilities require >99% reliability
- **Energy and power density**, amount of power or energy stored per unit of volume and/or weight. Determines the practicality of a given application and technology combination
- **Calendar lifetime**, time before the battery capacity decays below usable levels (usually a function of temperature and time)
- **Cycle lifetime**, number of cycles (charge discharge) before the battery capacity drops below usable levels
- Efficiency, in terms of delivered power versus input power, >90% is desired, >75% is acceptable

Figure 3: Mapping of battery technologies and applications to key functionalities



Source: Purdue, Arthur D. Little analysis

Figure 4: Key drivers of levelized costs per battery type[21]



Finally, **cost**, often expressed as Levelized Cost of Storage (LCOS)[22], is a critical parameter which will determine the economic viability of a given application. The LCOS of electrochemical storage technologies is a function of the upfront capital costs, lifetime (calendar and cycle), efficiency and particular characteristics of the application. This is discussed in more detail below.

From a technology point of view electrochemical systems encompass an array of chemistries, ranging from familiar lead-acid and lithium-ion systems, to less well-developed approaches such as flow and sodium-sulphur batteries, through to emerging battery chemistries such as zinc-air, lithium-air, sodium-ion and lithium-sulphur. Supercapacitors, which store charge in an electrostatic field, also fall into this category. An overview of the key cost parameters for the main battery types is provided in Figure 4.

Due to strong synergies between power applications and both electric vehicles and consumer electronics, much of the recent focus of battery development has been on **lithium-ion (Li-ion) batteries**. Indeed, Li-ion systems do have a number of advantages for grid applications, including high energy density, rapid response, very high efficiencies and flexible operation (discharge from seconds to four or five hours). These features enable lithium-ion batteries to be used for most applications in principle.

Furthermore, massive investment by companies such as Tesla/Panasonic and LG Chem is pushing down costs (and raising production rapidly). For example, battery packs for vehicles from some of the major players (Nissan (Leaf), General Motors (Volt) and Tesla (Models S and X)) decreased by 70% from 2005 to 2015.[23] While lead acid batteries' retail prices have decreased by 5% in Germany over the last three years, retail prices of Li-ion batteries have fallen by close to 20% over the same period[24]. Additionally, the technology continues to evolve and improve, with many new chemistry variants under investigation. This will be further analyzed in our forthcoming study on *Battery Technologies and Costs*.

21 EASE, Resource-E-Storage report 2016, Hybrid energy storage systems for renewable energy applications, ENEA consulting, Energy Storage, global conference – Brussels – 2016
22 Total lifetime cost of battery divided by the cumulated stored energy. The LCOS can be used as a first indicator to compare costs between different battery types and broadly position batteries compared to more conventional generation. However, levelized costs highly depend on the applications and batteries and should only be compared on this basis. (See discussion in text)
23 Source: Nissan, Tesla Motors, DOE, Deutsche Bank, BNEF, Navigant, EIA, Arthur D. Little analysis
24 Energy Storage, global conference – Brussels – 2016

Nevertheless, Li-ion batteries do suffer from some disadvantages. They remain relatively expensive, in both energy and power terms, despite recent cost reductions.[25] Additionally, safety remains an issue as electrodes are thermally unstable, which can lead to a thermal runaway. This means complex electronic circuitry is needed to reduce the prospect of fires or explosions to an acceptable level, which adds further cost. The disadvantages reduce the prospects for Li-ion batteries to be used in bulk energy-storage applications requiring many hours of storage capacity, e.g. arbitrage.

Despite poor lifetime and average efficiency, **lead acid batteries** remain the technology with the best cost/performance ratio today in terms of capital cost per kWh and kW. There is room for further cost reduction through mass production. Disadvantages of lead acid batteries include low energy density, which can be challenging in some locations (e.g. Japan), and toxic chemicals content. The technology is mature, but new generations of advanced lead acid batteries with improved performance (e.g. lifetime, energy density) continue to be introduced. Lead acid batteries can be used in most applications except arbitrage, given their energy density and therefore limited discharge capabilities at rated output.

Sodium-Sulphur (NaS) batteries have high power, high energy density and high discharge time, and are therefore particularly suitable for intraday energy applications (arbitrage, self-supply & TOU, stable output). The technology is approaching the maturity phase. NaS batteries rank average in terms of investment costs, efficiency and lifetime, leading to levelized costs on average higher than lead acid batteries, with less cost reduction potential than lithium-ion and lead acid batteries.

Flow batteries are at the R&D stage. One of their main advantages is the decoupling of energy and power. The main drawbacks to date include poor efficiency, low energy density and the use of toxic chemicals. Maintenance and reliability are also significant concerns. Similar to NaS batteries, flow batteries are best suited for large-scale energy applications such as arbitrage and stable output applications.

Supercapacitors have very quick reaction time and very high cycle lifetime, making them particularly fit for frequency regulation applications. Supercapacitors have low energy density and their costs remain prohibitive today for energy applications.

Nickel-metal hydride (NiMH) batteries remain costly today, with generally poor performance regarding lifetime and efficiency. They are particularly suited for frequency-response, frequency regulation and voltage-stability applications. Safety under high-power charge or discharge is an advantage versus lithium-ion technologies, and strong resistance makes NiMH batteries the preferred technology for applications in the transportation sector and extreme conditions (e.g. remote, off-grid).

Today, **the cost of battery storage technology is too high for large-scale commercial deployment**, other than where local regulations incentivize its deployment (See Section 5). Calculating LCOS is complex since it depends on the application characteristics, the overall system configuration, and the average shape of the charge and discharge curves, in addition to the basic parameters of the battery system (capex, efficiency, lifetime, etc.).[26] Values of the incremental cost of battery storage observed in the literature range between 400 €/MWh and 2,000 €/MWh for lead acid, between 200 and 1,500 €/MWh for Li-ion, between 350 and 1,000 €/MWh for NaS, and between 250 and 1,500 €/MWh for flow batteries. These levelized cost ranges are wide, even within specific applications, and will be investigated in detail in our next publication focusing on *Battery Technologies and Costs*. Estimates of the levelized costs of other alternatives such as reciprocating engines (between 150 and 200 €/MWh for gas and between 200 and 300 €/MWh for diesel)[27] suggest that in some cases batteries could be competitive, but for most applications the business case is not attractive compared to other alternatives.

However, as noted above the cost of batteries continues to fall, particularly in Li-ion, in which leading players are making huge investments in a bid to drive down costs and penetrate multiple markets. Assuming past learning rates continue, the best battery packs should become competitive with alternative energy applications by 2025[28]. However, it could be argued that basic extrapolation of learning rates is rather simplistic, since the costs of battery technologies are determined by factors such raw material costs and the fundamental physics of electrochemical processes, which may limit the ultimate potential for cost reduction[29]. This may push back the date of competitiveness with alternatives until the late 2020s. Of course, economics are not the only determinant of technology choice; aspects such as safety and portability can also play a role.

25 The range of capital costs for Li-ion batteries varies significantly due to variants in cell chemistry. These variants have different trade-offs between energy density, efficiency, safety, lifetime, etc.

26 For this reason, cost comparisons between batteries and other technologies should only be done on an application-specific basis.

27 Lazard November 2015

28 While battery costs have decreased significantly over the last years, inverter costs have not followed the trend due to lack of competition, and remain a large cost component of the battery storage solution for power-grid applications. The situation might change as OEMs seek to develop integrated solutions including inverters and put pressure on price.

29 In particular for batteries using lithium, limited resources might impact the costs in the long term.

4. Local regulation decisive in giving the boost to battery deployment

To date, much of the development in battery technology has been driven by the consumer device and, recently, in particular, automotive industries. However, the evolution of the energy market is rapidly escalating needs for storage technologies, meaning the power sector is likely to become a catalyst for cost reduction and technology development. Energy-market evolution calls for more flexibility in the network, which batteries can provide. The drivers for battery use in the power sector are discussed in more detail in the following section.

Fundamental drivers of battery storage

We have seen in the previous section that batteries can be used in various applications and by a broad range of market players.

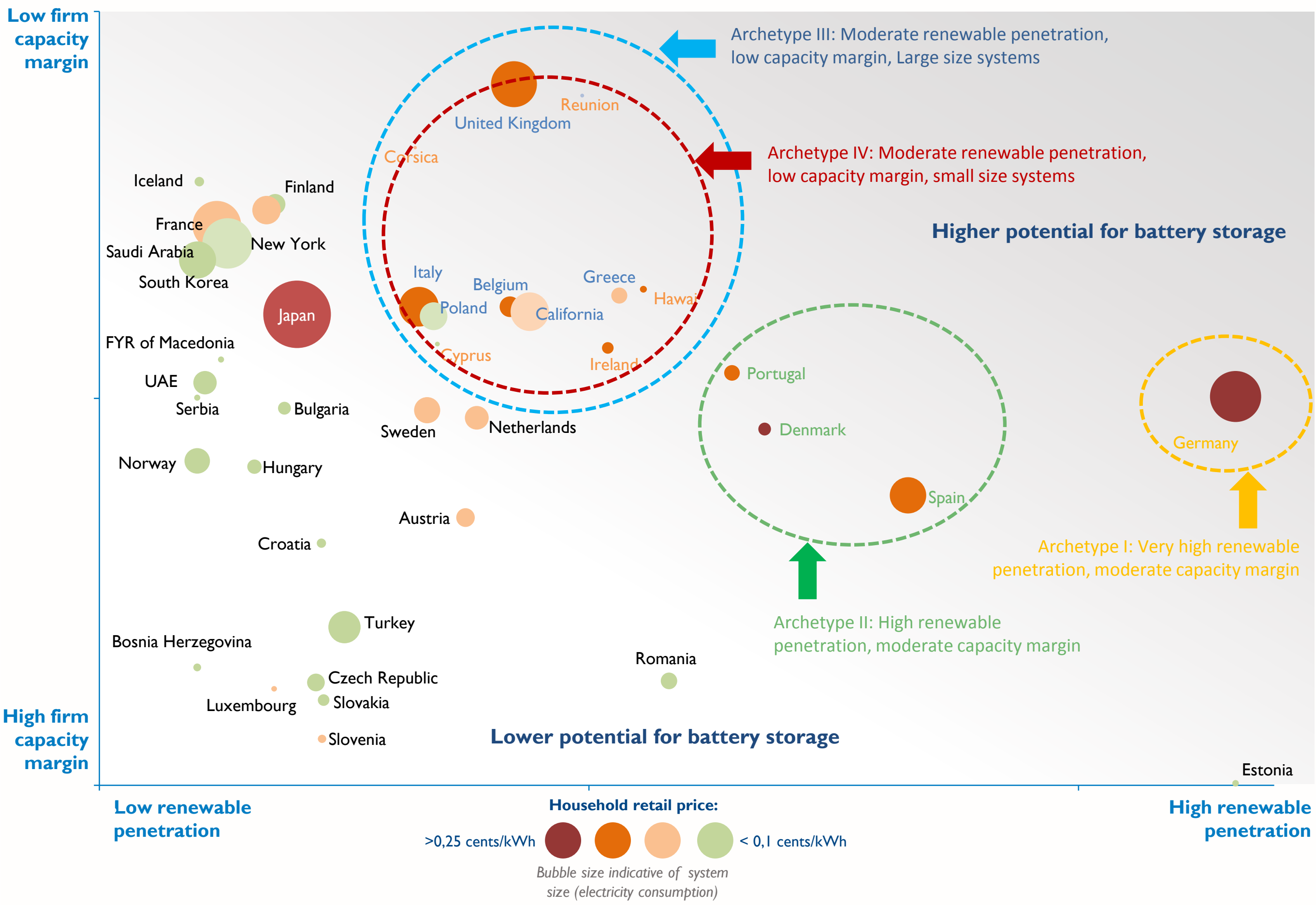
The flexibility offered by batteries becomes even more valuable as renewable energies develop and constrain system operation and planning. But renewable penetration is not the only parameter driving the business case for storage in particular markets. Table 1 summarizes the key drivers for storage deployment and the applications they directly address.

	Drivers	Rationale	Key applications
1	**High grid-renewables penetration**	▪ Need for further flexible generation to step in/out at short notice due to fluctuating, unpredictable power generation in the network ▪ *Tends to increase price differentials in the market through introduction of low marginal generation costs (see Driver 5)*	▪ Frequency response ▪ Frequency regulation ▪ Stable output
2	**Degree of physical decentralization of renewable generation assets**	▪ Pressure on the distribution network to accommodate new and unpredictable generation capacity in the network	▪ Frequency response ▪ Frequency regulation ▪ Stable output ▪ Voltage stability
3	**Tight flexible capacity margin**	▪ Reflects low flexibility in the system to accommodate intermittent renewables ▪ *Tends to go along with expensive generation at the margin, leading to high prices at peak periods (Driver 5) and high retail electricity prices (Driver 6)*	▪ Frequency response ▪ Frequency regulation ▪ Stable output
4	**Poor security of supply**	▪ Provision of enhanced security of supply with battery systems (coupled or not with renewables) at all times or during network outages	▪ Self-supply & TOU
	Enablers	**Rationale**	**Key applications**
5	**High peak/base-load price spread**	▪ Benefits the battery-storage business case by increasing revenues from charging/buying electricity during low price periods and selling/discharging during high price periods ▪ Price spread is closely related to the generation mix, including renewable share and capacity margin	▪ Arbitrage
6	**High electricity retail prices**	▪ Incentives for optimized self-production through a combination of self-generation (from PV, for example) and storage (e.g. store surplus for later usage)	▪ Self-supply & TOU

High renewable penetration (grid and distributed) and tight flexible-capacity margin have been identified as key drivers, conveying an indication of both flexibility needs and the underlying economics (e.g. price spread and retail prices).

A selection of countries have been mapped against these two drivers, allowing identification of high-potential countries for battery deployment, on Figure 5.

Figure 5: Countries mapped against key drivers of battery deployment[30]



This framework highlights groups of countries that face similar constraints, representing potential for battery deployment. Among these high-potential groups are countries at the forefront of storage development and deployment, such as **Italy, the United States (California), the United Kingdom and Germany**. On the other hand, other markets under similar conditions have, until now, only seen very limited development of batteries. This could be explained by:

- The development of alternative storage technologies (hydro-storage and pump-storage plants, CAES, flywheels, power to gas) and/or **alternative business models**, providing indirectly similar flexibility services (e.g. interconnection, distributed conventional generators, DSR). Despite high costs, key competitive advantages of battery storage compared to alternative storage technologies and business models are **rapid deployment**[31] (versus the development of connections, interconnections and hydro-storage) and **reliability** (versus demand-side management);
- Lack of strong political involvement to clarify the **regulatory framework** and **market mechanisms** and lack of willingness to bring down the major **cost barriers** left today. Examples of levers include **clarifying the role of TSOs and DSOs** related to storage, reviewing the **procurement of system** services (eligibility and combination of services) and reconsidering **taxes and fees** on storage to avoid double charging (load and generation).

30 Firm capacity margin evaluated based on installed intermittent capacity, incl. interconnection on peak demand; renewable penetration evaluated based on intermittent renewable installed capacity at peak demand
31 Hence the importance of energy and power density and module size
32 EENews, May 2015
33 Interconnection capacity represents about 20% of the peak demand

Deployment status, enablers and alternatives

Germany

Archetype I: Very high renewable penetration, high capacity margin

The German power system is characterized by high penetration of distributed (PV) and centralized (wind) renewable generation, and a booming residential storage market. Policy measures have been promoting hybrid distributed systems (PV + batteries) for more than two years now, in order to accommodate distributed renewable penetration in the grid. The **KfW programme 275**, for example, provided a 30% investment grant for equipment purchased with low-interest loans until the end of 2015 to residential customers who could see their on-site consumption increased with batteries[32]. While high retail prices also facilitate the business case for residential batteries, incentives are playing a key role in a market where the average state of charge of batteries approaches zero over the first three months of the year. Potential savings achieved with residential battery storage for self-consumption are fundamentally lower in Germany than in other markets, such as California, which benefits from favorable irradiation all through the year. However, this also presents opportunities for VIUs and system operators to use residential batteries as additional storage capacity over this period, as discussed in Section 3.

Compared to the residential sector, the industrial and commercial (I&C) sectors have so far lagged behind. And still, retail prices are high, capacity margin is decreasing with the closing of nuclear plants, and I&C-owned renewables are ever growing. But the incentives for German I&C are not there: network charges and tax regimes do not promote I&C storage. Furthermore, Germany's high interconnectedness with neighboring markets[33] means that excess supply is better sold to neighboring countries than stored and kept for self-consumption or for later hours in the day. In a nutshell, integrated power grids via interconnections lead to a smoothing impact on power-price spreads and volatility, which goes against part of the battery-storage business case.

Spain

Archetype II: High renewable penetration, high capacity margin

Battery deployment in Spain remains very limited despite a high share of renewables in the network. The government started cutting back on subsidies for renewables in the past five years, and the new self-consumption law adopted at the end of 2015 is expected to adversely impact residential battery storage. Under this new law, hybrid battery-storage owners will not be able to decrease their maximum connection capacity and therefore benefit from lower network charges. So although market fundamentals (e.g. high deployment of PV panels, relatively high retail prices) are present in Spain for the widespread development of residential battery storage for self-consumption, the absence of incentives slows down the deployment of battery storage.

32 EENews, May 2015

33 Interconnection capacity represents about 20% of the peak demand

United Kingdom

Archetype III: Moderate renewable penetration, low capacity margin, large size systems

The United Kingdom is one of the key battery markets in Europe:

- Changes to the policy and regulatory landscape are ongoing to further support the deployment of batteries. The launch of a call for evidence was announced for summer 2016 to investigate ways to facilitate use of flexibility before a reform is proposed by Spring 2017.
- National Grid foresees 1GW of non-pumped storage by 2020, providing regulatory barriers are removed.
- In response to the flexibility challenges already faced today in the UK, National Grid ran the Enhanced Frequency Response auction during summer 2016, which resulted in 200 MW battery storage clearing the auction, with April 2017 as the earliest start date.
- In the Irish Single Electricity Market, where the share of renewables is higher than in the UK, AES recently commissioned a 10 MW battery to provide fast-response ancillary services, and initiated the first step of a planned 100 MW battery project[34].

On the other hand, the deployment of battery storage at the residential level remains limited in the UK: residential PV is less developed, battery prices are too high and subsidies are insufficient compared to the retail price.

Battery storage competes with other flexibility tools on the market such as interconnectors, flexible generation and demand-side management. Distributed conventional generators, in particular diesel generation, have lately had significant success with current grid challenges in the UK. Responding to market signals, distributed conventional generators are regaining interest with VIUs, generators and merchant players to generate revenues from capacity mechanism and ancillary services and reduced network charges (TRIADS).

About 1.1 GW[35] small-scale distribution connected generators cleared the capacity mechanism auctions, hoping to capture revenues not only from the capacity mechanism, but also through embedded benefits that include the avoidance of transmission network charges. Stand-alone batteries today did not succeed in clearing the CM auctions, and hybrid renewables/batteries so far have not been allowed to participate in it.

The UK government, through National Grid, is also supporting demand-side response as a tool to provide flexibility to the grid. In fact, demand-side response is increasingly seen as a potential contributor to frequency response through the intermediary of aggregators (more details in *ADL's Viewpoint on Demand Side Management - Untapped Multi-Billion Market for Grid Companies, Aggregators, Utilities and Industrials?*). The business model consisting of incentivizing end consumers to reduce their consumption or switch to behind-the-meter generators to respond to grid requirements has been widely tested and enabled through regulatory changes. But the extent to which operators could rely entirely on third-party response and substitute assets, providing flexibility with DSR, has not been fully proven yet[36].

Demand-side management is not necessarily competing with storage applications, and can actually be complementary to storage when flexibility from Demand Side Management is not available. In fact, batteries could be used as a complement to behind-the-meter generators (e.g. hybrid generators) and activated through demand-side response.

34 National Infrastructure Commission, UK, 2016
35 Ofgem, June 2016
36 UKPN study

United States

Archetype IV: Moderate renewable penetration, low capacity margin

Activity in the battery storage market in the US is highly dependent on the state. California is one of the states with the highest renewable capacity (wind and solar), and a leader in battery storage deployment. Its 30% penetration rate of renewables and 70%–30% split of solar capacity between utility-scale solar and distributed PV has driven the deployment of battery storage at both grid and residential levels.

Beyond favorable fundamentals, the deployment of battery storage is supported by relatively high residential tariffs and strong regulatory signals, with California's Public Utilities Commission setting clear targets that require utilities to build energy-storage capacity and clarifying the market rules for behind-the-meter battery aggregation. Southern California Edison (SCE) acted as first mover and bought 261 MW of energy storage by the end of 2014, 100 MW of which were from AES and 85 MW from Stem (both battery storage). Stem also recently won close to 1MW capacity in the demand-side response (DSR) auction held this summer by Con Edison for the state of New York, testifying to the complementarity of battery storage and DSR.

The state of New York is also one of the early adopters of battery storage, and currently clarifying market rules for enabling battery storage to access the market.

In the PJM (Regional Transmission Operator, part of the Eastern Interconnection grid), the creation of fast regulation reserve combined with pay-for-performance framework introduced by the Federal Energy Regulatory Commission have promoted the development of battery storage with about 250 MW[37] energy storage (flywheel and battery storage) installed to date. However the decrease in clearing prices, namely due to falling oil prices, have raised concerns on the economics of battery storage.

Other parts of the United States, such as the Northwest, will likely be later adopters given their significant hydro-resources and the flexibility provided by hydroelectric and pump storage, which are sufficient to manage current levels of renewables.

Archetype IV: Moderate renewable penetration, low capacity margin, small-size systems

Island markets

Spain Greece France Italy UK

Island markets have seen a lot of activity in battery storage. The unique challenges faced improve the business case for battery storage: networks are more quickly saturated given their smaller grid size and higher generation costs driven by more expensive generation mixes (e.g. diesel generators). Battery storage is an opportunity for these markets to support the development of renewable energies, support decarbonization of markets often heavily reliant on oil-fired generation, decrease exposure to oil prices and potentially reduce costs. Island markets also have fewer available alternatives to add flexibility to their systems: pump-storage plants are often not an option, and interconnection is weak if existent. So it is with no surprise that most countries have concentrated their pilots on these islands when possible: La Gomera and La Aldea de San Nicolas (Canary Islands) in Spain, Azores (Graciosa Island) in Portugal, Tilos in Greece, La Réunion in France, Sardinia and Sicily in Italy, and Hawaii.

Pilots have so far focused on grid-scale batteries within hybrid configurations or stand-alone providing support to the grid to enable renewables integration.

In Hawaii, where about 90% of solar capacity is distributed PV, HECO recently announced it would finance and deploy residential storage to resolve grid congestion and enable more distributed PV to connect to the grid. This is one of the few examples where utilities are paying for and remotely operating residential storage. A couple of grid-scale hybrid configurations have also been announced: Ambri battery storage next to a wind farm on Oahu's North Shore, and SolarCity's solar PV battery project on Kaua'i.

Some islands have made energy storage mandatory for every new renewables plant in the system in order to better manage intermittency: Puerto Rico, La Réunion, Guadeloupe, Martinique and Azores.

37 Resilient Power, PJM, February 2016

Arthur D Little

5. Fast move for some, wait for others – shape for all

Battery storage is expected to play an important role in responding to the current challenges posed by the deployment of renewables.

However, today there are a number of barriers to its implementation, such as regulatory uncertainty, commercial arrangements, maturity of technology and associated costs.

In the short term, the deployment of battery storage in specific markets will depend not only on market characteristics (e.g. renewables penetration, interconnectedness, generation mix, the network's topology and system size), but also the regulatory framework, incentives and commercial signals in place to enhance the battery storage business model:

- **Grid-scale storage** for **frequency regulation** and **stable output applications** are seen as the most promising[38] applications today. While it has significantly developed in countries such as Japan, the US (California) and Germany, residential battery storage comes only third because of the difficulty of building a positive business case without strong support from public policies;
- In most countries (except Italy) system operators are restrained from developing battery storage solutions beyond pilots because of the regulatory definition of battery storage and the role the regulator expects from a system operator to play;
- The combination of applications is essential today to stack revenue streams and build a positive business case. Current market design (definition of ancillary services, access to grid services and the possibility of stack services) is often not adapted to make the most of battery storage;
- Even if the regulatory framework is clarified and system operators are allowed to own and operate batteries, the business case will continue to be challenging in the short to medium term to provide the sole grid-support services. Combined ownership is considered the most likely, economically viable solution for system operators.

So is it too early for battery storage?

- For **residential hybrid PV/storage,** current commercial developments show that the opportunity is now **where proper incentives are in place**. In leading markets such as Germany and California, VIUs already differentiate themselves and enter the battery storage market to broaden their offerings. VIUs are not alone in this market, and the role of aggregators continues to expand and evolve to cover battery storage, either as software providers or technology operators, though somewhat slowed down by the evolving regulatory framework, their access to ancillary services and energy market;
- For grid-scale applications, it is time for **early adopters**. **Power utilities** are stepping into the market and a series of large-scale commercial battery storage contracts have been announced over the last year. The majority of these contracts will provide flexibility services (e.g. frequency response, frequency regulation) to the grid and benefit from arbitrage. **Island markets**, under the initiative of system operators, have been leading the market in terms of grid-scale battery deployment (combined with renewables to stabilize output or for frequency regulation) by power utilities and, in some particular cases, directly by system operators;
- The deployment of battery storage by industrial and commercial customers is likely to remain limited in the short term given the current challenging economics, with the exception of the telecom industry presenting particular challenges related to accessibility and security of supply;
- **System operators** have so far been very cautious regarding the integration of batteries in their portfolios and limited themselves to pilots. The current regulatory framework and prohibitive costs have led batteries to be considered, if anything, an **asset of the future**.

Battery storage is a **fast move** today for some actors in the value chain and a **wait** for others, but for all it is a **market to shape** and a **strategy to develop** now if they don't want to turn up late at the party.

38 Applications that make the most economic sense today

"Battery storage is a fast move today for some actors in the value chain and a wait for others. But all actors can shape the market and must develop their strategy now if they don't want to turn up late at the party."

Authors

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www.adl.com/BatteryStorage

Arthur D Little

Digital future of electrical networks

How can electricity utilities tackle the digitalization challenges of their network business?

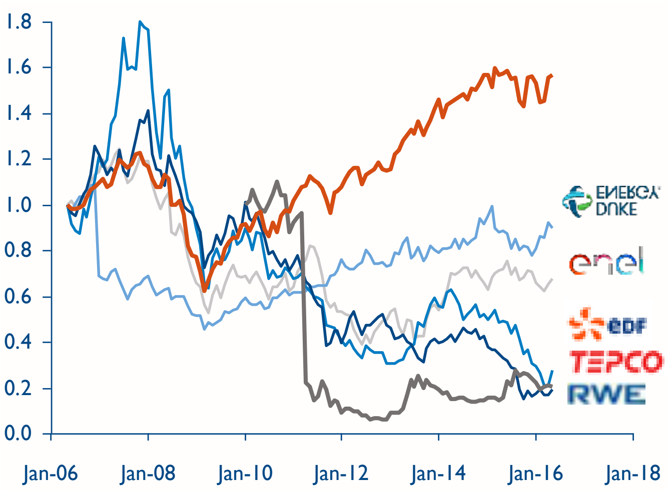
Digital transformation is one of the most important changes the utilities industry faces these days. This transformation is not limited to changing how companies interact with their clients, but also impacts the way they operate internally, as well as where and how value is created. In order to prepare for this landslide transformation, electricity companies must adapt their practices to facilitate such a change.

Key triggers for digitalization of utility companies

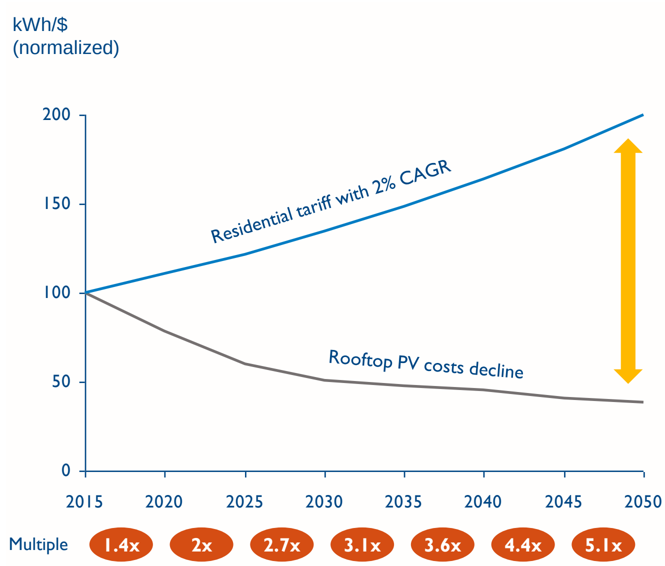
Digital transformation is increasingly impacting businesses around the world. The ubiquity of the Internet and the extremely rapid expansion of disruptive technologies have changed the dynamics within several industries. As mentioned in our recent digital transformation study[1], from entertainment to the car industry, almost no sector of the economy has been left out of the digitalization wave.

Electricity companies are not an exception. Several internal and external triggers should warn utilities that digitalization is vital for their survival.

First, utilities are struggling to deliver healthy financial performances. A constant network cost structure, coupled with the decline in on-grid consumption (mainly driven by the growth of decentralized renewable resources), means utilities are experiencing shrinking profit margins.



Growth of decentralized renewable resources and the consequent decrease in electricity wholesale price were the main drivers for the decrease in market value



Source: IEA, DB report

1 Arthur D. Little, Digital Transformation – How to Become Digital Leader (2015 Study)

Plotting the trends in share-price value from 2006 to mid-2016 has shown that the value of traditional utilities has fallen by 60% to 90% compared to the value of the Dow Jones Industrial Index within the same period.

The trend could worsen, as the current grid parity of residential renewables is no longer considered the final price level in many geographies. In fact, rooftop PV is expected to be almost two times cheaper than on-grid tariffs in 2025, and up to five times cheaper in 2050 (see Figure above), according to International Energy Agency[2] data.

More advanced network management processes will be needed to optimize network capacity to fulfill consumer demand. This can be done at minimal cost only by working with big data analytics, which enable accurate prediction of the impact of distributed generation resources and management of optimal energy flows in the network.

Without such capability the gap between network tariffs and distributed generation costs can increase even more. In the worst case this may lead to an unprecedented boom of off-grid solutions for some end customers, making parts of the network obsolete.

On the other hand, network utilities should also view these future trends as an opportunity to fully transform the network business into a provider of value-added services to end customers and an enabler of efficient use of distributed generation resources via virtual power plants.

All this can be done, but as mentioned above, hardly without significant digitalization transformation efforts to enable network utilities to manage this far-more-complex business. There is an increasing set of technologies that will allow network operations to become more effective and efficient, and choosing not to adopt them will lead the electricity company to fall behind in this industry transformation.

The impact of digitalization on network management

In most industries, digitalizing is seen as a way to react to new market developments rather than save costs. However, for network companies digitalization also presents several opportunities for cost efficiency. A recent Arthur D. Little case study showed that early digital adopters improved their EBIT margins by up to 8 percentage points compared to the laggard companies within 10 years. Some of the relevant use-case examples include the following:

- The use of **custom-built substations** enables networks to build assets directly on site and optimize space utilization due to custom-built equipment
- The use of **geolocation apps** to pinpoint network events via crowdsourced information from customers enables accuracy and sizable reductions in operating expenses
- The use of a **common information model** to integrate all platforms used in the control center, including the likes of SCADA, OMS, DMS, GIS and CIS, reduces inefficiencies of asset conditions and performance with predictive analytics
- The use of **smart meters** in consumer households reduces energy losses and operating expenses by allowing utilities to provide improved peak-demand management
- The use of **drones** for supervision, inspection and detection of any irregular event can significantly reduce maintenance costs and resources utilized
- The use of **IP cameras** to monitor key assets and worker productivity in real time reduces the need for manual inspection of progress
- The use of **augmented-reality glasses** to provide technicians with assistance during maintenance tasks can reduce costs due to downtime through faster and better maintenance
- The use of **virtual training software** to fully prepare field technicians for all types of maintenance tasks reduces downtime losses

Another opportunity for utilities is increased quality of operations and network performance through digitalization.

- **Advanced control-center software** functionality constantly analyzing the optimal network set-up enables elimination of unnecessary losses caused by overloading
- The use of **self-healing automation** tools and sensors, coupled with **advanced fault localization** methods, enables faster resolution of unplanned outages and minimizes the number of customers impacted
- The use of **live-line robots** enables monitoring of transmission lines and the performance of repair tasks without loss of supply
- The use of **tele-robotics** with steady manipulator arms increases safety of distribution-line repairs, preventing hazardous injuries to field technicians

Whether you look at it from a financial or an operational point of view, the impact of digitalization on networks is already changing the industry.

Identified risks and challenges of digitalization

However, these opportunities may also carry some risks. In ADL's digitalization transformation study, the major challenge to digital transformation turned out to be lack of a sense of urgency. This issue is specifically seen in the network

2 IEA Technology Roadmap – Solar Photovoltaic Energy (2014 Edition)

businesses of utility companies because there is limited competitive pressure, even compared to sales of generation business units. This is potentially very dangerous, especially in markets where there is high potential for distributed generation business. In these markets outdated business models could result in an underperforming network providing rudimentary services.

Another issue network utilities often mention is linked to difficulty understanding the available and future digital technologies. As there is limited standardization and minimum use cases available, it is also difficult for management to decide which technologies they should include in their digital transformation roadmap, and when. Furthermore, the usual "me-too" effect might sometimes lead to adoption of the wrong digital applications because the benefits might be very company specific. For example, it currently does not make much sense for a utility with a reliable underground network to fully automate all of its feeders, since it is impossible to justify costs with very limited benefits.

Electricity companies should also be aware of the risk that lies in the implementation of digital transformation programs. This is, by nature, a very complex and lengthy effort, with a strong possibility of multiple failures that have been unacceptable in this type of business in the past. Digital projects need a risk-taking attitude, and learning from failures is part of the new culture, which can be built by bringing in new digital talent and creating incubators instead of only training existing employees.

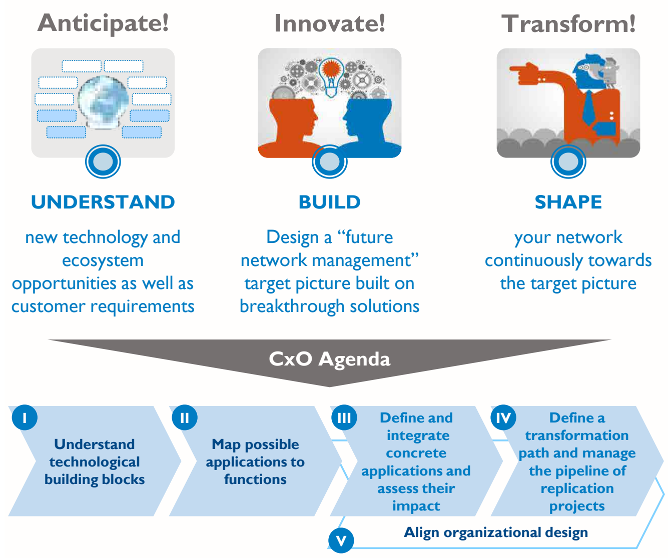
Moreover, utilities will also need to manage external environments while implementing their digital transformations. There is a risk that legislations and regulatory bodies will not recognize the digital efforts of electricity companies in their regulated revenues. Utilities need to keep communication channels open, because managing stakeholders' communication during this transition phase is crucial for a success.

Our approach to addressing the challenges of digitalization

In order to support utilities in digitalizing their networks, we have developed a five-step approach that helps CxOs to deal with this challenge (see Figure below).

First, companies have to understand the different technological building blocks and their potential applications in network management. These building blocks affect different functions and can be categorized in the following manner.

- Data
  - Virtual manufacturing/simulation
  - Augmented reality
  - Predictive analytics



Source: Arthur D. Little

- Connectivity
  - Cyber-physical systems
  - Internet of Things
  - Collaborative robots
- Equipment
  - Additive manufacturing
  - Smart energy systems
  - Advanced machining and material science
- Value chains
  - Converging ecosystems
  - Decentralization
  - Collective intelligence/crowdsourcing
- Products and people
  - Smart, ecological products
  - Virtual workplace/workplace 4.0
  - E-learning

Second, companies need to map the possible applications to the corresponding network functions, which can be segmented into five categories:

- Network planning and engineering
- Network construction
- Network operations
- Network maintenance
- Support functions

After mapping the digital applications to the different functions, the next step is to define and integrate concrete applications in order to assess their impact further. A deep analysis needs to be performed on the financial and operational impact of the selected digital applications on each network function.

Thereafter, companies need to define their digital transformation paths and manage the project pipeline to ensure rapid benefits realization and a consistent, preferably self-financing transformation of the electricity company. This can be done by first identifying the digitalization initiatives, then selecting projects for validation, which will be further launched as pilots. Once the benefits have been confirmed, electricity companies can start the roll-out and industrialization of these successful pilot applications. Finally, after the roll-out has been completed, constructive feedback should be collected in order to maximize the output and reap the benefits of these investments.

As a final stage, companies need to develop organization and governance models for adaptation by establishing appropriate partnering strategies, digital organization units and governance models.

Conclusion

The struggle to deliver a healthy performance, the necessity of optimizing network capacity to fulfill customer demand at minimal cost, and easy access to disruptive technologies are all contributing factors to creating a step change in the way electricity companies look at their network management.

For this reason we believe it is the right time to ask some critical questions. Does your company understand the new technologies and digital transformation opportunities? Can you develop a practical strategy in order to reach your desired digital transformation target picture? And do you have the required capabilities to successfully implement your digital transformation?

Arthur D. Little has longstanding experience in digital transformation in the utilities industry, across developed and emerging economies. We have gained deep insight into the potential consequences of digital applications and their impact on electricity markets. We support clients in devising strategies to transform their companies from the traditional to the digital end of the spectrum, in order to protect their commercial interests.

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Arthur D Little

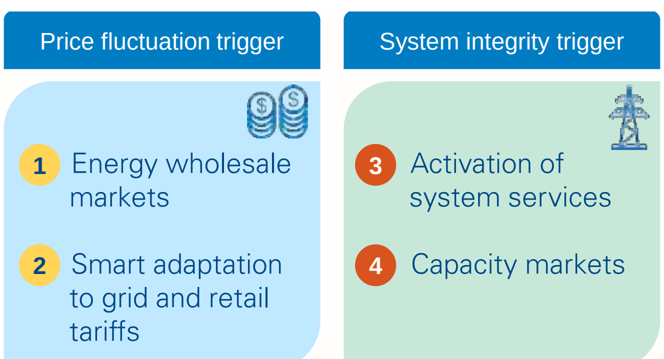
Demand side management

Untapped multi-billion market for grid companies, aggregators, utilities and industrials?

In times of energy transition, when intermittent decentralized generation is on the rise and large traditional generation assets are retiring, electricity systems increasingly need flexible solutions to ensure security of supply. Demand Side Management (DSM) is one such solution which energy firms should have on the radar. Although it can bring tremendous value to Transmission System Operators (TSOs) and an additional source of revenue for other market players, DSM is still surprisingly underdeveloped in most parts of Europe and beyond. The technical functionality is nevertheless straightforward: by adjusting energy demand when external signals are received, aggregators[1], industrials and even households can provide additional capacity and energy to the market, and be remunerated for it. So what is holding back some markets from unlocking these sleeping buffers in energy systems?

Four categories of DSM incentives are deployed on the international scene today

Two types of external triggers typically create DSM activity: Electricity system supply conditions and Electricity market prices. We identify 4 main mechanisms as the pillars of the DSM market today.



1. **Wholesale and balancing markets:** Access to energy markets to sell energy (or not consume it) in high price periods
2. **Grid and Retail tariffs:** Tariffs can vary depending on the time of day or season. Shifting consumption away from high tariff periods can generate savings for industrials or households
3. **System services:** The third mechanism covers primary, secondary and tertiary control services agreed between Demand Side Response (DSR) providers and the Transmission System Operator (TSO), and is designed to ensure security of supply[2]
4. **Capacity markets**: Sufficient capacity in the market is guaranteed through contracts established before the target delivery period, with remuneration based on the capacity made available

There is no wrong or right mechanism: generators, aggregators and end users can choose to activate their flexibility based on a price or a system-need trigger. They will favor one mechanism over another, depending on their risk appetite, their capabilities, and their overall ability to deliver.

Even though there is an advantage for participants in DSM to secure additional revenues through contracts, they can be significantly penalized in case of non-delivery, risk which should be minimized by aggregator interventions.

1 Aggregators aggregate the combined load reduction from end users and sell it to network operators
2 Demand Side Management covers TSO services and market imbalances while Demand Side Response valorizes flexibility at TSO level only, i.e. system integrity triggers mechanisms only.

By contrast, with price incentivized response, load is adapted to market or network price signals with a risk of market exposure or imbalance costs. Participants will not receive any payment as such – their reward is in avoided costs, which can be high. However, for industrial players the ability to reschedule production processes in line with grid tariffs or energy tariffs is not guaranteed.

Risk monetization is not the only decision factor for flexibility providers to select one DSM product over another. Indeed, time response, duration of activation, load direction (up or down), frequency of activation per year and availability of load are conditions which can constrain participation in the provision of DSM. For instance, a high number of activations over the same year, especially if in quick succession, will create increasing pressure on the production operations for an industrial and potentially offset a larger portion of the avoided costs than desired. Appropriate valuation of the applicable mechanism is required in order to compensate the related costs and therefore to ensure an appropriate level of participation.

Through various client assignments, we have found that some mechanisms are very well adapted to some production and consumption types – while others are not. The understanding and mapping of DSM mechanisms to flexibility providers' constraints are key steps to enable optimal value extraction from DSM.

Although regulators and network operators understand the importance of DSM as a new source of flexibility, DSM is still surprisingly underdeveloped in Europe

The majority of markets have developed DSM mechanisms, though at very different paces. The United States, supported by state regulators, is undeniably the leader for incentivizing DSM providers to participate in the market. Selected European markets have also embraced the importance of facilitating their access into the energy market to ensure security of electricity supply. However, the examples below in the table illustrate the very slow ramp-up in even the most advanced markets.

DSM facilitation has improved but more can be done

With many energy systems "under stress", DSM penetration can and should be further stimulated. Not only does it help Transmission System Operators to manage their networks more effectively (i.e. deferred reinforcement capex, decreased network losses, reduction in costly temporary isolated

Markets	Status
France	In its 2015 Generation Adequacy Report, RTE states that the cumulative demand response capacity available exceeds 3 GW, contributing currently to the provision of ancillary services. DSR could represent up to 50% of the procured mFRR (Manual Frequency Restoration Reserve) and more than 7% of FCR (Frequency Containment Reserve) in 2015. However, despite favorable conditions for DSM operators, only 38 MW of DR capacity has been certified through the new capacity market for 2017, representing only 0.04% of the total certified capacity.
United Kingdom	From 2018/2019, a capacity market will be also deployed in the UK. Similarly to the French case, the last set of auction results published in December 2015 demonstrated the weak level of awarded DSR capacity, representing only 1% of the total awarded capacity.
Belgium	Large grid users or aggregators can participate in the primary reserve (R1) and tertiary reserve (R3) through tenders organized by Elia. Where traditional gas-fired power plants used to be the main source for highly reactive provider of primary reserve, now aggregated consumption from large industrials offer an alternative to conventional generation, as indicated by the aggregator REstore. The supplier is remunerated for the capacity made available while there is no remuneration per activation. There is no capacity market in Belgium yet, however by 2017 it is expected that Elia will open all its reserves (R2 in a pilot mode) to all market players and for all technologies (Load, Batteries, Generation asset). Current DSR capacity called by Elia in Belgium amounts to 850 MW, roughly 6% of installed generation. As a result, Belgium now ranks in the top countries in Europe in terms of ancillary services opened to DR.
Germany	As opposed to the Belgian systems, German TSOs remunerate generation and pooled assets for being available during a certain window, and an energy payment if the plant is called during that time. However, the minimum bid sizes for the secondary and tertiary reserves are higher (5 MW) in Germany compared to 0.1 MW in the US or 1 MW in Belgium, which prevents the participation of small DSR providers. Another main blocker for DSM participation in Germany is the opportunity given to suppliers to validate the use of their own end users' flexibility. As suppliers are not encouraged to favor DSM (i.e. they protect their generation assets against DSM mechanisms), they tend to not encourage DSM participation in the market

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Markets	Status
Italy	A limited number of balancing products is currently designed to accept flexibility from DSR providers. The interruptible contract programme managed by Terna is the single mechanism giving access to market participants to monetize their flexibility, with a load curtailment minimum to 1MW and not allowing aggregation. The Italian market understands the existing regulatory scheme needs a reform and the definition of a capacity market is ongoing, with effect from 2018-2019. In parallel the Market of Dispatching Services (MDS) is under review to allow all sources of flexibility and types of technologies to supply power to the dispatching system.

generation), it also enables utilities, aggregators and electricity users to capture extra value in the struggling electricity markets.

Unlocking this value-added requires various initiatives at different levels. Our experience and interactions with TSOsS aggregators and industrials allow us to recommend four initiatives to increase participation in DSM:

I. Improve market design

Access to the DSM market must be facilitated via attractive and fair market mechanisms in order to improve the participation of end users and prevent discrimination between actors in the energy value chain. This is one of the key barriers in those markets where DSM penetration is low. The main actions here for TSOs and regulators should be:

a. Treat Demand Side Management on equal and transparent terms with generation in the provision of ancillary services and in capacity markets; and design specific mechanisms for DSR providers (i.e. and not to adapt mechanisms that were once designed for generation asset owners)

b. Rationalize the number of mechanisms to limit overlaps, and therefore cannibalization, and also to limit their proliferation. Today, it is often difficult for demand side providers to identify which products are suited best to their operations

c. Create viable and tailored products that enable aggregators (and their users) to unlock the real potential of DR in the market

d. Appropriately incentivize risks taken by utilities and industrials

e. Develop specific value propositions to be put forward to the regulator if room for Demand Response in the market has not yet been created via regulation

f. Create alignment between market players on the baseline methodology to be used to calculate the available load reduction of a given resource to respond to a need for flexibility

II. Educate and support industrials to engage in management of Demand

Although the benefits for industrials are real, much more flexibility can be unlocked. Some examples: United Utilities, a UK Water company, stated that it expects to make £5 million in revenue from DSM by 2020 by reducing power usage, including by turning off pumps at its treatment works. REstore, a European aggregator, stated that primary reserve capacities can earn €180k per MW per year in Belgium. Key actions to take (by TSOs, regulators, aggregators, utilities) are:

a. Inform and educate industrials about additional revenue streams via Demand Response, and the economic value proposition. Indeed, industrials active in Steel, Paper, Food & Beverage, Water treatment, Glass industries and others have high interests to reduce their consumption or shift it to another time. Total, ArcelorMittal, Tereos are examples of high energy consumers which became DSR providers

b. Support companies to identify adjustable manufacturing processes that are able to free up flexibility for the market when required

c. Develop and tailor DSM products and mechanisms that are adapted to a company's operations, to its risk appetite and to the expected benefits

III. Develop real time price signals

Real time price signals are required to incentivize and trigger DSM activation, but also need to integrate and reflect those activations. This is in the hands of the market manager, typically driven by TSOs:

a. Implement Time of Use tariffs to incentivize shifting of consumption

b. Design wholesale markets (Day-Ahead and Intraday markets) capable of sending real time price signals for unlocking flexibility when required

IV. Collaboration of aggregators and energy suppliers

Partnerships between aggregators and energy suppliers can bring high added value although their implementation will only be possible in the absence of conflict of interests. Aggregators' DSM technical knowledge and their capacity to advise industrials on shifting or reducing the consumption of their production assets, associated with the existing customer portfolio of energy suppliers, jointly work to the advantage of the industrial player by easing market access for them and enabling optimal leverage of the know-how each party brings to the table.

In addition to the above recommendations, infrastructural and technical solutions in support of Demand Response can be envisaged to facilitate reactivity and availability of assets. We distinguish battery storage as one of the domains that is gaining more and more popularity across the energy value chain, and can be part of the answer to decrease risks on the DSM provider side and increase responsiveness. Alternatives like distributed generation and electric vehicles are other means to bring generation up or demand down to satisfy grid constraints. Positioning and subsidies from the EU and regional regulators are expected by various market parties in Europe, and should be part of the solution to facilitate and increase DR usage in grid balancing.

Conclusion

Aggregators, energy suppliers and electricity network operators have demonstrated in a few European countries their willingness to rely on end users' flexibility to respond to grid needs. So far, with great success, but still somewhat limited in scope.

The understanding of needs and constraints of DSM providers is, however, required to design the market appropriately in a way that will facilitate and increase flexibility activation.

On one hand, TSOs need to design and propose a range of simple mechanisms adapted to their real needs and to DSR providers constraints and expectations in terms of incentives, with a limited impact on operations and certainly not acting as a penalty for the DSR provider. Another critical activity here is to educate the market accordingly.

On the other hand, aggregators, integrated utilities and end users need to define their strategy to seize the "DSM business potential". The value proposition needs to combine the additional revenues (upside) with pro-actively managing complexities and risks (technical and business constraints). In this, an open-minded exchange with grid operators and regional regulators should aim to then converge into a clear setting out of the requirements to facilitate DSM deployment in regional markets.

The challenge will be to define a tailored and non-discriminatory solution for all flexibility owners along the energy value chain, sharing different expectations. Since real cases have proven to be beneficial for a broad range of stakeholders, capturing this value in the energy markets is definitely a prize worth active pursuit.

Authors

Kurt Baes and Florence Carlot

Imperatives for growth in power

How European Utilities can create value again

European utilities are currently undergoing significant reinvention due to a rapidly changing market and political environment. The traditional energy generation model is under fire, while at the same time demand is shrinking due to changing habits. The industry desperately needs to develop new business models to ensure new top-line growth. How can this be achieved, and how can utilities create value once again? This article discusses the imperatives and opportunities driving change in the market.

There is no doubt that the business model of power utilities operating in developed markets is currently poised for major transformation. As we have discussed in previous Prism articles, The Future of Energy Utilities (2/2013) and Radical Changes for European Power Utilities (2/2014), the traditional vertically integrated, centralized, asset-heavy, generation model is being questioned from many angles, not least economically. As a consequence, valuations of most leading utilities have been severely reduced, reflecting the loss of value in generation portfolios. As anticipated, we are witnessing different types of reorganization by some leading players as they shift away from this model. The most publicized is perhaps E.ON's formation of Uniper, separating conventional power generation (coal, natural gas and hydro) midstream gas and global energy trading activities from the "New E.ON", which will focus on renewables, energy networks and customer solutions. They are not alone: RWE, Centrica, ENEL and NRG, to name but a few, are also reorganizing in different ways to shift their focus away from conventional generation.

Once the asset depreciation and reorganizations have taken place, the question is then how to create value once again. In a continuing context of stagnating or even decreasing demand in many markets, there is no need for further capacity investments to meet new needs, while replacing old power plants is fraught with uncertainties – and by its nature will not be a growth solution. Our previous articles highlighted the fact that, other than investing in renewable generation assets, most of the opportunities for growth in developed markets lie downstream, in the trends and shifts affecting consumer energy usage and its energy mix. This article discusses some imperatives to grow the top line in those activities. More than ever, power utilities are looking for ways to grow

In Europe, demand for electricity is stagnant and, in many key markets, is decreasing. (See Table 1) In North America, utilities face a similar situation. The fact is that GDP growth in developed markets is no longer based in energy-intensive industries.

Moreover, in many countries, for environmental or balance-of-payments reasons, regulators and authorities are asking utilities to "sell less". Authorities in some markets are imposing a constant reduction (i.e. the US, where utilities are incentivized to reduce their customers' consumption, and the EU with its goal of 20% increase in energy efficiency by 2020), and are actively subsidizing energy efficiency measures with public funds, while being very vocal about the need to reduce energy consumption.

In this unfavorable context, CEOs are looking for ways to grow their top line in order to facilitate the transformation of the companies they lead, and to find substitutes for the revenues and income that traditional assets will no longer provide. Some are looking for international growth, in countries where there is need for generation capacity and infrastructure investments. Others have been seeking to invest in renewable generation assets and have created specific units to lead those efforts. However, the question remains – what can be done to grow the top line in the "home" markets? It looks very much as if the answer lies in downstream areas, and in taking advantage of the shifts in the energy mix and customer usage that are taking place.

Multiple trends impact the energy world, and provide spaces for opportunity

A number of major trends are affecting how consumers use energy. There are also numerous technologies that are changing the relative economics of different types of fuels, and thus, the final energy consumption mix of a country. Small-scale, distributed generation and power storage is opening up space for households and enterprises alike, as well as cooperatives and other associations of local consumers (or producers-consumers). While distributed generation takes away revenues from the utility, it leads to new sources of service revenue: customers need services in the provision, optimization, operation and maintenance of the local energy system. Local generation and power storage offers opportunities – but also risks – for a utility. There are many prospects: service fees might partially compensate for the loss in commodity revenue, longer contract duration and highly individualized services reduce churn, while add-on services are easier to sell, especially when they are app-based. Distributed energy, however, opens the door for new competitors: photovoltaic (PV) panels, electric cars, heat pumps, micro-CHP and battery storage, as examples, are "entry products" which could be bundled with power and gas contracts by their respective OEMs, thus taking the customer away from the utility. This is already a reality. On the back of cost reductions and technology improvements, several utilities have launched packages of PV-storage-energy together with battery-technology providers to preempt this threat and capture the opportunity themselves. These include Duke Energy/Green Charge Networks, Green Mountain Power/Tesla Powerwall, and RWE HomePower Solar/VARTA.

Energy efficiency and energy cost savings are another growth opportunity, driven also by regulation, which ranges from legal requirements for energy management systems in larger firms, as applied in Germany, to customer energy savings targets for utilities, as in Austria. Many utilities, as well as other specialized firms, offer energy audits and energy management services which help the customer to monitor and control energy consumption. Contracting of heat, steam, power, pressurized air and other process inputs is a well-established services business at many utilities. Further sources of revenue exist "behind the meter": buildings, facilities and industrial sites need improvements in energy efficiency by optimizing their operations as well as replacing equipment.

Similar to distributed generation, energy management and efficiency services lead to additional long-lasting revenue streams. The IEA estimates that European utilities' revenue in energy efficiency and management services activities is growing at 3-4% per year.

Although these tables vary substantially from market to market, our estimates, shown in Table 2, concur, and break this down into 2-4% in optimized end-use supply and up to 8% in energy-efficiency services.

This compares with negative growth in the traditional energy commodity supply business. E.ON Connecting Energies

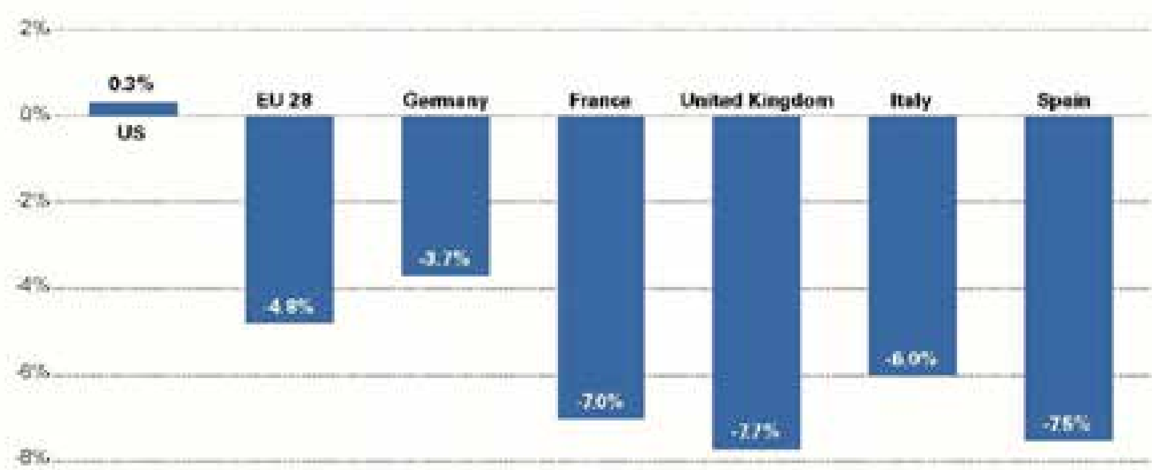

Table 1 **Change in electricity demand in the US and EU, 2010-2014** *Source: Eurostat, EIA statistics*

Arthur D Little

recorded sales of over €340 million in the energy services market. The more established COFELY (with services ranging from distributed generation to facilities management) achieves almost €15 billion[1].

Entering into new verticals is another relevant opportunity for growth: "smart" home automation offerings, electric mobility through charging stations, street lighting and more, are already part of the portfolio of utilities – but also of telecoms or industrial firms.

Point solutions, such as smart thermostats or multi-room media, still dominate the sector, but the growth potential through greater penetration and the connection of solutions is massive. The "battle" for the smart home is already taking place among platforms and eco-systems that are being developed and commercialized by players from different industries. The AT&T Digital Life platform, Google's purchase of Nest and RWE SmartHome are examples of this.New growth is expected from tapping into the plethora of consumer and grid data that opens up opportunities for new business models, ranging from grid stabilization services to sharing platforms, on which consumers trade locally generated power at distribution grid level. The concept of the shift of role from central utility to facilitator, or "smart integrator", is already foreseen by National Grid in the US within the context of supportive changes in the New York State regulatory framework.

On top of the main opportunities discussed, there are also utilities reflecting on what transportation conversion to gas or power on a mass-market scale might mean for them. Understanding the transportation sector and recognizing specific potential growth areas for the medium- and long-term future is another key trend. The potential switch of marine fueling to LNG and the necessary changes to port infrastructure to facilitate this is a good example , creating opportunities in commodity supply, engineering and management services.

However, these new businesses are outside the "comfort zone" of the classic power utility, and companies need to recognize that pursuing such opportunities is one or several steps away from their day-to-day business and capabilities.

Imperatives to grow

In this context of important shifts in many areas at the same time, some aspects are important to focus on for success:

1. Getting the basics right in the "core business" is a must

As in any commercial organization, the "core business" needs to be run effectively and efficiently. This might not be as simple as it seems, as most industry leaders have millions of customers that cover different market segments (from families and individuals to corporations), and are constantly the target of local regulatory authorities. As an example, the big UK utilities have long struggled with IT system changes impacting on billing accuracy and cash flow; in 2015 Npower lost 10% of its residential customers and paid £26 million in fines to the

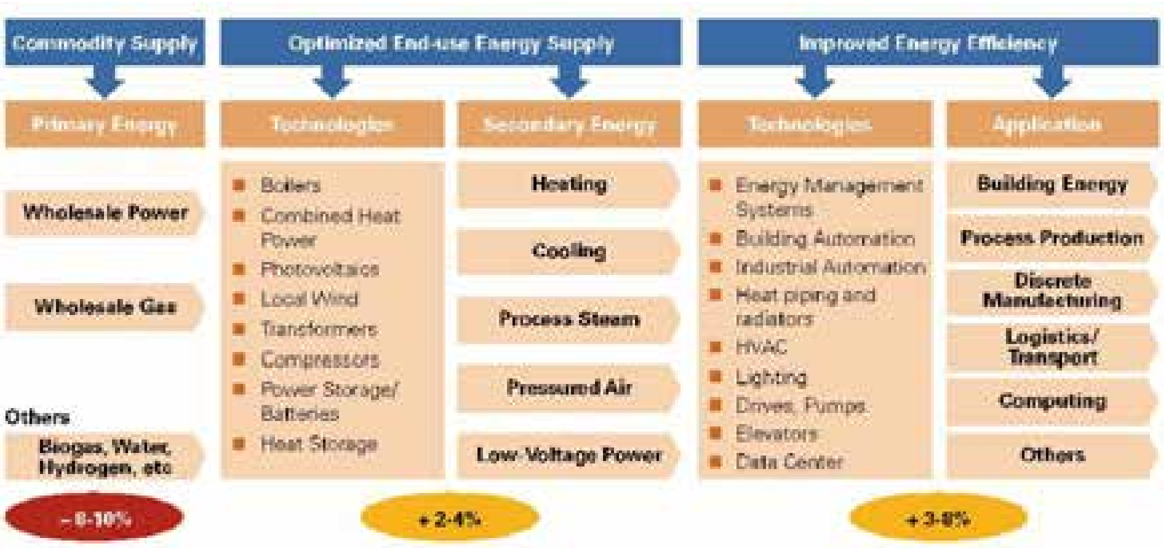

Table 2 **Energy services opportunities include all stages of the energy supply chain at end-user premises. This is where scope for positive revenue growth lies, compared to negative growth in centralized commodity sales – the old "core business"** Source: ADL analysis, US DoE, IEA, RWE, E.ON, IRRC Institute

1 Sources: IEA Medium Term Energy Efficiency Market Report 2015; E.ON Connecting Energies

regulator due to unresolved customer complaints connected to billing issues.

Nevertheless, as we observe in our continuing client work and benchmarks[2], there continues to be significant work that needs to be done in areas such as customer service (where there are still many "push factors" that drive customers away), in understanding customer needs, in managing customer churn and in building effective marketing and sales channels.

As well as the "core business", these are imperatives for any other product or service business that a utility might be interested in developing and pursuing.

2. Choose your battles (& competitors)

Many of the opportunities mentioned, and many others, can be interesting endeavors. However, in most of them there are already established businesses, while most leading utilities are also already in the process of entering them. Therefore, incumbents are facing competition from other, similar players as well as from new, more nimble and focused rivals around each particular product or service.

A review of the plans announced by leading utilities in Europe identifies that none of them wants to miss out on any of these opportunities. It seems that they are all willing to pursue pretty much everything that moves – developing new hardware for home energy monitoring, creating their own IT platforms to link their services, digital apps of all sorts, building engineering groups to provide installation and maintenance of distributed generation, solar rooftops, etc. Taking the UK as an example market, all the Big six utilities offer energy services, but these can range from residential boiler sales, PV installation and community projects through to industrial energy management. One of the companies even states it purposefully uses this "simple title" to describe a very wide range of offerings, the list of which reads like a home for any product or service outside of energy commodity sales rather than a business unit with a purpose.

While large companies might have the resources to pursue many of these opportunities, it is important that they recognize that different business opportunities might require different skills and capabilities, face different competitors, and need different business models, among other things. Even large companies cannot compete with everyone – they need to pick their battles and assess which ones they are likely to win.

This is particularly true in the service arena. It is open to entry by a variety of start-ups and local players on one hand, and at the same time by international specialists that leverage expertise gained in one market to target another. A thorough assessment of how competitive a company might be on a service is critical to building sustainable strategies.

A pragmatic approach to this strategy problem is to look at the existing key strengths, competencies and value proposition a utility has in new business fields. Different approaches can provide valid alternatives:

- Focus on the reliability of energy supply. "Keeping the lights on" is the main concern of most customers, especially in a distributed world. Utilities can clearly make a difference to other "point solution" vendors by offering a "holistic" service with a guaranteed performance. Market research shows that utilities are strongly positioned with customers for energy services, despite any innate paradox of commodity supplier/efficiency driver, and can offer holistic approaches beyond the capabilities of other players. The key distributed-energy competencies of a utility exist today in distribution grids and power plants where the highest availability levels, stable operations and safety are required. A candidate for growth therefore is operations services for distributed-energy systems/equipment that require flexibility (e.g. demand response, storage).

RWE recognized its strengths as a trusted energy supply and producer, and dynamic trader, along with the fragmented nature of the German distribution network sector and the difficulty in managing distributed energy effectively. With a big enough connected base of distributed production facilities, there should be portfolio effects and improved possibilities for grid management and value extraction. A partnership with Siemens has provided the technical expertise to make this virtual power plant theory a reality. Aggregation and coordination of the distributed output means that power can be sold at the EEX (power exchange) or on the balancing market, plus dispatch can be managed to support grid stability. The next-generation Smartpool project was announced by RWE and Siemens in late 2015, and is planning to provide a mass-market IT platform to widen participation – a further step towards the smart integrator model.

- Another option is to focus on the productivity and effectiveness of existing channels to build a "sales machine" aiming to maximize the sales of adjacent products and service bundles to the existing customer base. Some utilities build on this by pursuing a strategy to move away from selling "electricity" or "gas" towards a supply of bundles and solutions, which link the commodity with the inspection, certification and maintenance of installations as the main standard offering.

2 See our viewpoints: "Managing churn in power utilities" and "Power & Gas retail costs benchmark"

Arthur D Little

- Others might focus on leveraging their relationships and reputation with local customers and authorities to build presence in other services such as distributed generation and ESCOs (energy-service companies that manage all of the energy needs of a facility). Once the presence and capabilities have been established, such companies can think about further expansion.

Growth beyond the core must be carefully selected, especially when diversifying into energy-efficiency businesses or new verticals. A thorough and honest assessment of where each utility can add value and has a real competitive advantage is crucial to avoiding plans that will not translate into concrete opportunities.

3. Reorganize to build focused and performing businesses

Large incumbents are structured to serve their core businesses. Billing systems, for instance, are designed to be able to calculate and send accurate bills to millions of customers every month. Customer-care platforms are designed to provide answers to customer requests around a number of key interactions, in massive volumes. While many of these can be modified and changed in many ways, they are seldom at ease in adapting to products and services that apply to a fraction of those millions, but substantially increase their complexity.

Sales channels that sell power and gas are certainly able to cope with changes in the product portfolio, but they have difficulties when the nature of the service requires specific advisory or specific skills that the sales force does not have. This is often the case with many of these new types of opportunities. A typical challenge is changing the sales force from selling transactional commodities to complex, individualized services.

On the other hand, new engineering-based services and often digital product and services offerings have to be developed and customized in a much more dynamic and complex market environment. Many of these require their own "service development unit" and their own "service factory". In turn, these units require new capabilities. As an example, software and data will play a major role in the new business fields and thus require new capabilities such as "agile" product and software development, data analytics and prediction, just to mention a few.

The sales business of the future must re-organize in order to align business potential, priorities and KPIs, along with the resources and necessary capabilities for its different types of businesses and new ventures. Different options exist, but a good starting point is to think in terms of functional layers which interact on clearly defined targets and KPIs (the "layered model", shown in Table 3):

Table 3 **A layered model to reflect on how to reorganize for growth**   *Source: Arthur D. Little*

British Gas (Centrica) had achieved some initial success in 2011 with remote heating controls in the residential segment, based on technology provided by partner AlertMe (eventually acquired in 2015 for £44 million). The potential of the greater customer interaction the devices triggered was recognized, but also that speed to market was too slow and cumbersome, and opportunities to leverage the technology were being missed. Decision-making lines needed to be shorter and faster; new ways of working were needed to be able to sell interactive electronics rather than energy; specialist skills would have to be added for product development, sales and service; the link to the core utility and brand needed to be maintained in order to leverage connection opportunities between products and channels, and to keep some degree of control. Hive was deliberately located in central London, far from Centrica's HQ, with a tech startup-style culture. Eighty percent of the team was recruited externally, including from telecoms, media and software development; the remaining staff came from British Gas, keeping the connection to the core business, plus dotted reporting lines were put in place from Hive to the CIO of British Gas Information Systems. LEAN start-up and Agile methods were deployed to develop and bring products to market, using customer testing and fast product iteration. Customer management, marketing and sales are dealt with by Hive via its own team, brand and website, while British Gas's trusted brand in the home market and trained engineers are essential for installation. Low-cost, cloudbased CRM systems were set up so Hive could deploy quickly and avoid impacting a major IT change program in the core business.

Hive was set up in late 2012. The initial product launched in September 2013 as Hive Active Heating, providing remote heating control via a smart phone app. Around 250,000 smart thermostats have been sold in the UK; 3 million Centrica customers in the UK and US now have access to analytics and insight products. Lighting control, plug sockets and security sensors, plus a designer facelift to the hardware, were added in 2015, as Hive is conscious that the offering is intended to be as much a stylish, millennial product as it is a functional piece of technology.

- Service development units: to innovate on new services based on engineering capabilities, software or hardware (including energy equipment), or data-based, which can be combined from solution offerings by the product unit. Often service development is carried out by partners/suppliers.
- Product units: to market and develop standardized or customized solution offerings from commodity products and services and new, integrated service offerings, combining and integrating service "modules" (such as engineering offerings, software and/or hardware).
- Customer-facing units: to sell. For the core business this should be specialized by main segments or channels, combining commodity and bundled services sales for B2C, B2B and the wholesale market. For new services, new sales channels or sales models are required, perhaps under separate branding.
- Operations & infrastructure units ("service factory"): to deliver the product or service value to the customers, and operate distributed as well as centrally provided services and equipment, usually structured into technical plant services, energy management services and customer care and billing services.

In the end, in order to pursue some or most of these opportunities, power and gas retailers need to think about establishing new teams and organizations. These need to be freed from the utility culture, processes and systems in order to gain and maintain the agility required to compete in a service business. In some instances, it may also be relevant to distance new business areas from the core utility brand. A creative and entrepreneurial spirit is more likely to thrive outside the old core. Centrica's Hive business is a good example.

It is not only because of the different nature of the product or service that the metrics and KPIs of such organizations need to be changed. Many of these opportunities are emerging and will gradually impact different parts of the market. For some time, they might not stand out and get enough visibility in the parent company P&L unless they are measured separately. As an example, EnerNoc, a Nasdaq-listed US company successfully selling wholesale and demand response services, has revenues of a few hundred million US dollars, a table that would hardly be visible in the accounts of, say, the big European utilities.

4. Partner & venture

New services often require new business models, and these business models sometimes require partnerships and cooperation with others. If a company is planning to enter home energy monitoring and management, does it really need to design and make the hardware or own the IT and communications platform? Does it think that the value of the business is in the customer-usage data, in the design of the devices or in the installation and maintenance services of the hardware? Does it plan to bundle it with the power and gas contracts (maybe to aim for a customer churn reduction) or does it prefer a one-off sale?

Arthur D Little

Each company must reflect on where the key drivers of value are going to be for them and how it will differentiate and provide an attractive value proposition to its customers. However, each of these choices will have profound implications on the overall complexity and agility of the business to be set up. As many digital economy services are illustrating today, partnering can be an effective way to leverage others' capabilities while focusing the organization's efforts on the aspects that are most relevant for the business.

Nest Labs, started in 2010, launched its Learning Thermostat in 2011, and subsequently cameras and security products. Compatibility with a vast array of other manufacturers' products, from washing machines to pet feeders, allows linkages between devices to create greater energy savings and a smarter home, learning from the user's behavior. Google's acquisition of Nest for $3.2 billion in 2014 made global headlines.

Utility partners in the US include NRG, National Grid, Austin Energy and Con Edison, plus in the EU nPower, Electric Ireland, Direct Energie, Essent and Lampiris. Partnering with these utilities gives Nest access to around 100 million potential customers and a ride on the back of the utilities' trusted brands. For the utilities, the partnership offers a route into the smart home market without product investment and associated risk, plus the benefit of association with a growing tech brand.

5. Make a commitment

The energy world is in a state of flux. Ten years from now, the traditional commodity-focused retail business will not exist anymore in its current shape. There are many aspects that are changing, new technologies emerging and, all in all, a large amount of uncertainty. In those situations, investing in and managing a portfolio of options might be a good strategy for a large incumbent. However, when each one or many of these opportunities becomes a business itself and the incumbents' investments have to compete with companies that are extremely focused and already pursuing opportunities, the risk is that the strategy and investment does not receive enough senior management attention to become competitive and grow. There is currently a "window of opportunity" for traditional utility retail businesses. They must use this over the next five years if they want to achieve and maintain strong positions in the emerging and established markets discussed in this article. Otherwise, new entrants and established players from other industries will take pole position as the integrated energy, services player with customers. Given the size of the opportunity, but also the challenges, this means a complete transformation of the business, from strategy, business models, people and processes to partners. It needs a full commitment of owners and executive management to make a bold move, move ahead and drive transformation from the top. It must encompass the whole organization and make it agile, learning, and much more efficient.

Insights for the executive

The utility sector has historically been categorized by periods of accelerated and slow change: we are now in a period of accelerated change, and action is essential. In a context of stagnating or declining demand for electricity, there are many opportunities connected to, or at the fringe of, the core business in the "home" markets, where revenue growth is achievable – in the context of negative growth for many companies in the utility commodity business.

Some opportunities are clear and proven, others less certain and predictable. Betting on every horse spreads risk but limits the possibilities to establish a leading new business. Companies that make the effort to produce a strategic future view and filter effectively increase their likelihood of picking a winner.

The "imperatives for growth" discussed in this article are compulsory to achieve effective growth strategies. In many ways, utility businesses are already changing, transforming in structure and model. New ventures will require further business-model innovation to succeed. Distancing themselves from the old "utility culture" may be essential. At the same time, with many players developing relevant skills and technologies that are already active, partnering is an attractive possibility. Growth lies in energy services, connected services, and customer-oriented operations, but within these areas there are many opportunities and models. The pragmatic approach is to focus on core competencies in order to determine the direction to drive the business forward – while an external view can help determine which competencies and direction are truly relevant. For utilities, packages and holistic services can be the value-add that competitors miss.

However, on the other hand, reorganizations, new ventures and adjusting focus to future prospects can distract from core operations. Our experience shows that improvements here are (almost) always possible. In a business that is more and more service driven, losing touch with the performance of the traditional utility unit can be fatal.

Authors

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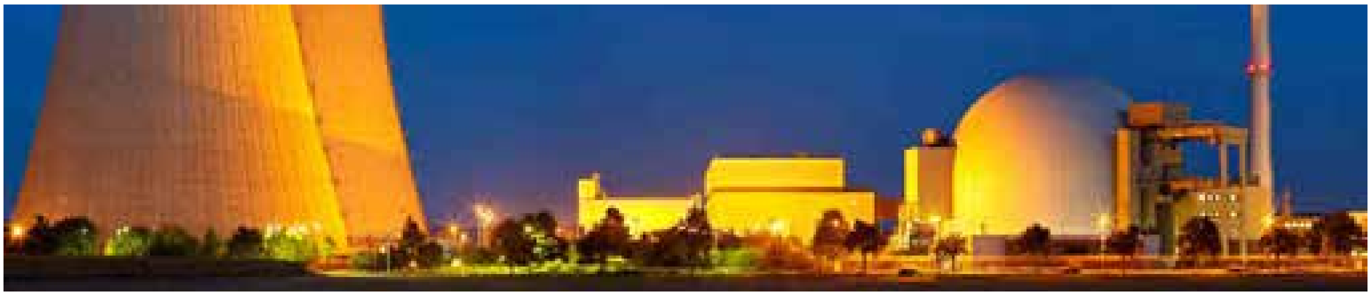
Arthur D Little

Nuclear Failures

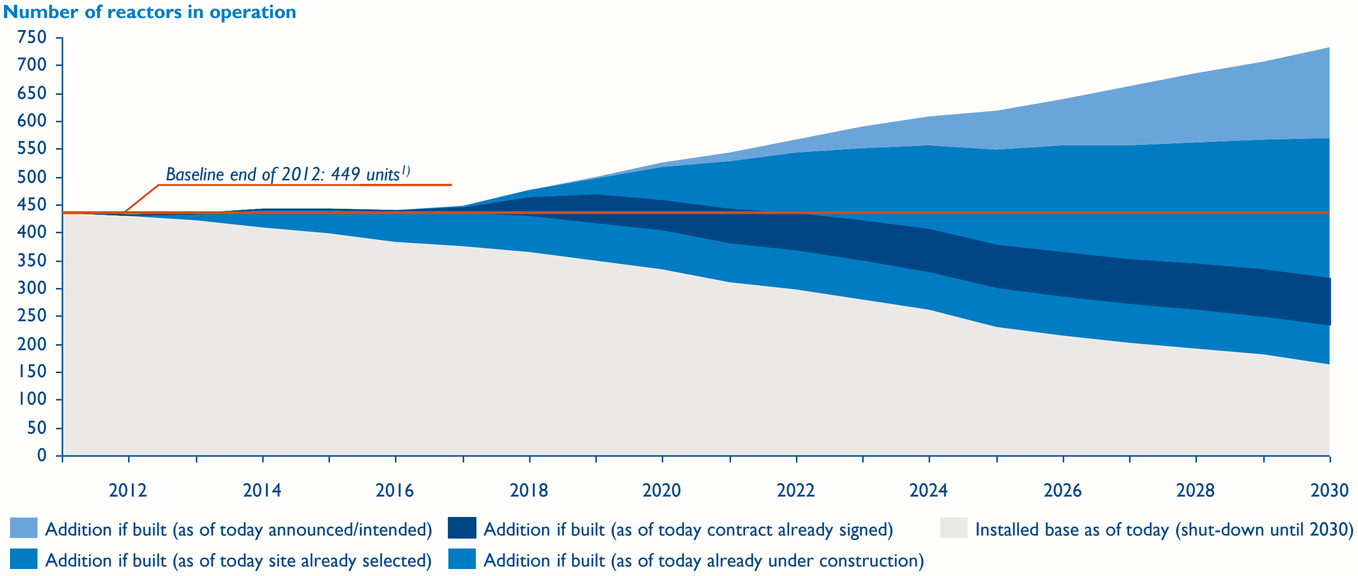
Risks, uncertainties and future potential



In 2011 the tragic events at Fukushima called the nuclear industry to a sudden halt. In the months after the accident, several nuclear program, for example, in Switzerland, Thailand, the Netherlands and, to some extent, also in the US, were put on hold or stopped entirely. Now, about five years later, it is evident that the global nuclear industry has recovered from this shock and is back to speed, albeit at a slower pace. In the beginning of 2017 close to 450 reactors had been under operation in 30 countries, and owners had proposed ti build and operate around 800 reactors. This shows a clear path forward for the nuclear industry.

This large number of proposed reactors reveals a remarkable fact: it is expected that the number of operated nuclear power plants will increase to 2030 compared to today's status-quo, despite contradicting indications from some media (see Figure below).

Development of installed nuclear base to 2030



1) Including operated but temporarily shut-down units, e.g., in Spain, Switzerland and Japan
Source: Arthur D. Little Analysis (2017-05-01)

This positive scenario, however, does not show the number of nuclear programs which "failed" to continue with their project development or construction activities and have either stopped entirely or been put on hold indefinitely.

A recent Arthur D. Little study identified more than 10 nuclear programs totalling 45 planned reactors which have ceased existence during the last five years, several of them before Fukushima. Another 25 nuclear programs with about 70 reactors put their plans on hold during this period, to a large extent after Fukushima. If and when these programs continue is uncertain. On the other hand, countries such as Turkey are pushing to advance their programs rapidly, and China will match its number of installed reactors with that of France within the next 10 years, becoming the world's second-largest nuclear-power producer after the United States by 2025.

There are two main reasons why a nuclear new-build program fails. The most obvious is, to a large extent, exogenous to the owner and originates in a country's nuclear policy and state or public opinion of nuclear power as an energy source. In Switzerland, for example, despite an expected electricity-demand supply gap within the next decades and a low-carbon energy policy, the Swiss Bundesrat decided to abandon nuclear power as an option in the wake of Fukushima, due to a wave of public opposition. As a consequence, three Swiss energy companies stopped their nuclear new-build plans only a few months after Fukushima.

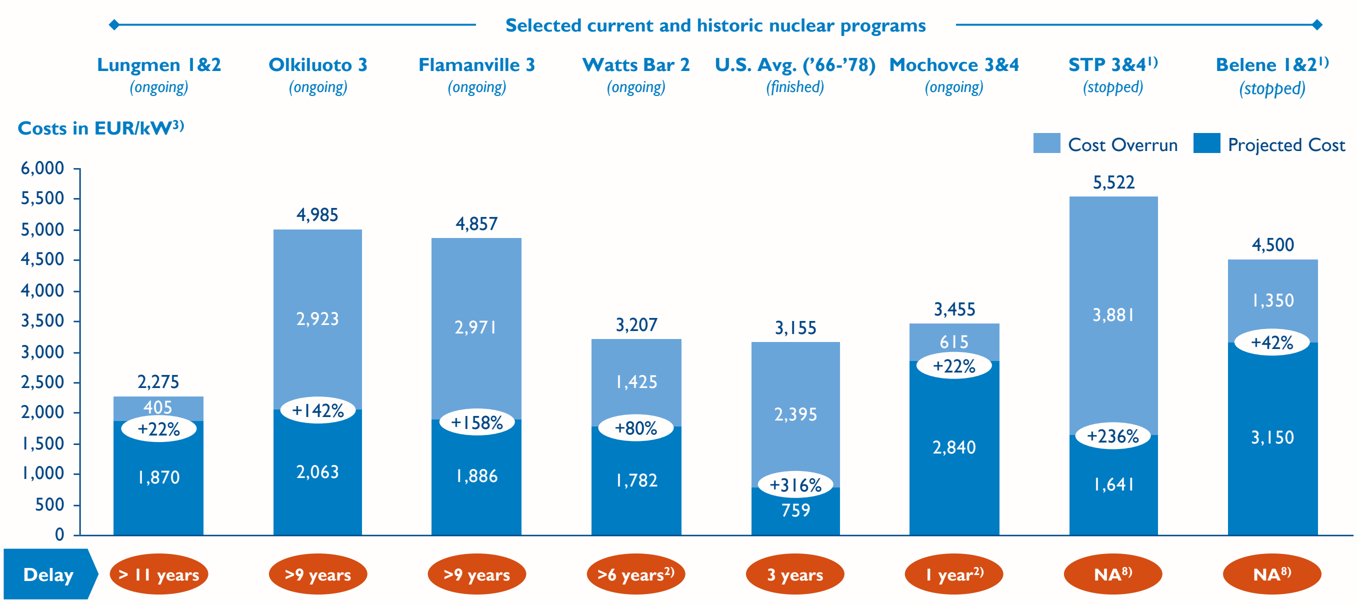
Similarly, in Lithuania, the Social Democrats forced a non-binding public referendum on whether Lithuania should build a nuclear reactor. The referendum was held in conjunction with the national election. About 63 percent of those voting in the referendum said they did not want additional nuclear power.

These examples show that, unless there is an exceptionally strong link between the country's ambition to establish a self-sustainable nuclear industry – meaning jobs to the people – and the nuclear program, earning public trust and confidence is crucial for the program's success. This is a major reason why the nuclear programs in countries such as China, India, Russia and Turkey progress well.

The other reason for failure originates in economic realities. Investment costs for several nuclear power-plant new builds averaged around €3,900 per kilowatt (see Figure below). In contrast, the investment cost for one of the world's most advanced combined cycle gas turbine (CCGT), Irsching 5 in Germany (860 megawatt), was less than € 500 per kilowatt. As long-term prices for gas are expected to continue to be comparably cheap, the nuclear option is also less attractive from a fuel perspective and hardly reaches its required return on investment.

The rationale of economic viability is not new to the nuclear industry. Even before the tragedy of Fukushima, skeptics of nuclear energy argued that the nuclear industry's prospects

Selected current and historic nuclear programs



Note: 1) Projects canceled or under revision, construction not started, yet; 2) Projects are restarts, time before restart not included; 3) Cost values with 15-12-15 F/X rates
Source: Arthur D. Little Analysis (2016-12-15)

were dimmed by delays and escalating costs that had long undermined the economic viability, and hence competitiveness, of nuclear energy. Since Fukushima, this view has received even stronger justification, especially in liberalized energy markets where increasingly volatile electricity prices put the high number of reactors - which are still proposed - at a certain risk.

The first wave of commercial nuclear-reactor programs in the US for example, which were introduced during the late 1960s and 70s, faced, on average, three years, delay and a remarkable 300 percent cost overrun relative to the original estimated investment cost. However, at that time, in many industrialized countries including the US, nuclear energy was viewed as a state industry vehicle driving economic advancement, and overall cost was less of an issue as energy-market prices were regulated.

Nowadays however, several nuclear programs are facing significant challenges to meet their envisaged return on investment due to schedule delays and exceeding cost projections.

Hence, a major for driver avoiding failure of a nuclear new-build program is to maximize the plant's economic viability by limiting cost escalations and schedule delays. Interestingly, this premise is well-known to owners of nuclear new-build programs; however, remarkably few projects, notably Chinese and South Korean ones, seem to be able to execute their ventures within the limits of this premise.

At the root of the failure often lies an inaccurate understanding of project risks. In addition, inaccurate prioritization of critical activities and lack of capabilities for project organization and suppliers have led to significant delays and budget overruns. In the past, several projects tended not to be ready for this challenge. Projects in Finland (Olkiluoto 3), the US (South Texas 3 & 4), France (Flamanville 3) and Russia (Kursk 5) have demonstrated these risks dramatically. Historically, several factors have led to cost overruns, including:

- Start of construction before design completion and inability of the owner to communicate its utility requirements in a comprehensible manner
- In ability to incorporate regulatory requirements into the plant's design, and lack of reliability in the licensing process
- Insufficient schedule integration (starting by having the end in mind) and communication between first-tier suppliers, sub-suppliers and owner
- Lack of strategic and operational planning by the owner (governance, milestones and so on)
- Insufficient project management capabilities, including controlling progression of the new-build project (time, costs, quality), across all key suppliers
- Poor interface definition and management between involved parties (including the regulator)
- Non-transparency of major project risks and hesitant implementation of counter-measures for identified risks and constraints
- Lack of understanding of needed capabilities over time, and hence lack of timely provision of suitably qualified and experienced staff.

A tangible example: During project development some owners, especially in countries with weak grid infrastructure, tend to underestimate the effort and time needed to provide sufficient grid infrastructure for the plant. Instead, they focus their efforts on the technology choice for the plant, not considering the impact the plant will have on the entire electricity system of the country.

These challenges of not understanding the interdependencies of a nuclear venture are amplified by an unspoken reluctance among project members to deal with the high degree of uncertainty involved in nuclear new build, which sometimes impedes progression further.

All these issues show that, while the technical complexity of nuclear new build is widely recognized, the root cause of a program's ultimate failure is the inherent management challenges. These are often underestimated and call for professional management of new-build ventures, which goes far beyond methodical program management. Deep understanding of the nuclear program itself is needed. Remarkably, on a theoretical level many owners are quite aware of these factors which determine cost overruns to a large extent. However, they fail at building the needed capacity within their own organizations to address these existing challenges.

Authors

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Arthur D Little

Why risk management is failing

Embracing complexity and uncertainty with value-based risk management

In today's business environment of uncertainty, complexity and continuous change, conventional risk management approaches are all too often ineffective: they are poor at dealing with complexity, too slow to adapt, and focused on reporting outcomes rather than supporting decision-making. A different approach – "value-based risk management" – can help organizations strengthen their decision-making capabilities and ultimately achieve better alignment with the strategic needs of the business.

Introduction

Effective risk management requires businesses to manage uncertainty. Industry convergence, accelerating technological disruption and the wide public availability of information increase the potential sources of uncertainty, and so complicate risk management. Organizations typically respond by developing comprehensive risk management systems – often referred to as enterprise risk management (ERM). The great majority of larger organizations already have ERM systems with varying degrees of sophistication.

> 92% of responses to a 2015 survey indicated **Enterprise Risk Management** systems were already in place

However, despite the prevalence of ERM systems, significant unwanted events continue to occur and cause serious damage to organizations. Those deemed newsworthy are sometimes catastrophic in nature, leading to significant financial impact or loss of life. Recent examples include the highly publicized use of engine management software by Volkswagen to "cheat" on emissions tests and the 2015 record fine of USD 20.8 bn given to British Petroleum following catastrophic events at Deepwater Horizon (the "Macondo Incident").

As companies face a future of increasing uncertainty, disruption and complexity, there are questions as to whether conventional approaches – such as ERM – are up to the job. We believe there are several practical ways to improve the effectiveness of risk management and better align decision-making with the strategic needs of the business. Collectively, we call our enhancements value-based risk management (VBRM).

The limitations of conventional approaches

We classify conventional risk management approaches as either "accountant" or "assurance", explained below. Both are widely adopted and used to manage a very wide range of risks from safety through to operational, asset and reputational risks. Both, however, have limitations that may lead to unforeseen risks emerging to damage the business.

"Accountant" approach

This approach focuses on comprehensive risk screening, evaluation and reporting. Systems described as "ERM" (i.e. including a broad portfolio of different risks) are often synonymous with the "accountant" approach. The principal weakness of this approach is that the high-level nature of reported risks is difficult to assure. ("How do I know risk x has been mitigated effectively?") This assurance is further complicated by the often-comprehensive documentation and reporting of risk data, but not of information for decision-making, which can create a false sense of security that risks introduced by the strategy (what the organization wishes to achieve) are being properly managed ("blinded by numbers").

"Assurance" approach

This approach focuses on known key risks and their mitigation. It is popular in high-hazard industries such as oil and gas, in which the significant risks are well known, but can be limited in its ability to identify new risks as circumstances change, given its focus more on upfront mitigation and less on ongoing management over a prolonged period. This particularly applies to risks applying across more than one strategic dimension – for example, a safety and reputational risk. The "assurance" approach often fails to adequately deal with complex systems. These are systems in which the relationships between cause and effect are often unpredictable, even with the application of expert knowledge – not recognizing the inherent uncertainty that this brings to risk management.

The benefits of VBRM

VBRM is balanced enhancement of these conventional approaches that concentrates on decision-making as opposed to simply risk reporting.

> The defining characteristic of **value-based risk management** is a focus on decision-making rather than simply risk reporting

We describe this approach as "value-based", as it leads to healthy questioning of what is required to support decision-making. In our experience, these questions often lead to a significant reduction of effort expended on activities that do not prove to be core to agreed strategic priorities of the business.

A review of risks using such an approach addresses the weaknesses of both "accountant" and "assurance" approaches, focusing risk management efforts where they will deliver the most value to the business.

There are four main pillars of VBRM.

We have experience of applying a VBRM approach effectively in large organizations with existing ERM systems in situations in which unwanted events persisted, and in companies that were not getting the return they were expecting from their considerable ERM investments.

We describe each further:

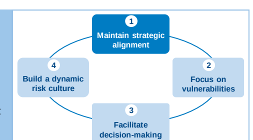
Maintain strategic alignment

At its simplest, strategy is a high-level plan to achieve one or more goals under conditions of uncertainty. Strategies can be developed and changed rapidly, but the supporting management systems and processes that implement the strategy have much greater inertia. The root causes of poor risk management are often found in this disconnect between the strategy and the management systems and processes that are required to deliver it, when the former have changed but the latter have not kept pace. This is increasingly important in today's uncertain business environment, in which agility and the ability to flex strategies rapidly is a key success factor in staying ahead.

Maintaining alignment means avoiding making decisions that do not support strategy, and communicating priorities clearly to business units. This requires companies to "let go" and simplify, focusing on areas in which expert systems can provide meaningful results that support decision-making.

Maintaining alignment also means allocating clear risk ownership, defining responsibilities and determining suitable empowerment for adapting systems and processes to respond to changing risk profiles. Some major risk areas will naturally align with business and functional units, and ownership will be clear. Others may not – requiring governance to be specifically agreed.

Case study: aligning business cases to strategy

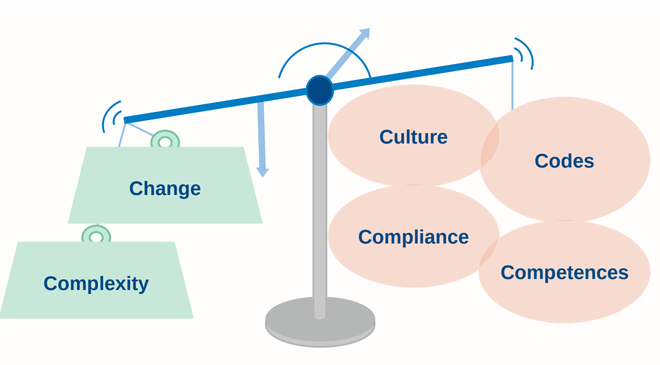


A multinational automotive manufacturer critically needed to improve the likelihood of project success on time and with expected quality. We developed new risk metrics that indicated the timing of emergence of key risks during the project lifecycle. The metrics were used to develop business cases showing why some projects should be stopped at the earliest opportunity, and others selected based on likelihood of success. This enabled the manufacturer to focus its effort on projects with much higher likelihood of success, and avoid wasted resources on projects which were less likely to succeed and not aligned with strategic business priorities.

Focus on vulnerabilities

One of the drawbacks of the "assurance" and "accountant" approaches is that they are often poor at indicating where to focus effort to make risk controls effective. This is important, because different hierarchies within the business often implement risk controls. Failure to understand why those hierarchies may be poor at implementing the controls prevents effective risk management implementation. This could be, for example, the absence of appropriate competencies within business units to understand a required risk-control measure.

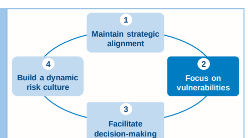
There are few pragmatic diagnostic models available to the risk manager for assessing vulnerabilities across all risk dimensions. An approach developed by Arthur D Little to help in this process is the so-called 6C model (illustrated below).



The 6Cs are Codes, Compliance, Competency, Complexity, Change and Culture. A 6C assessment considers the suitability and completeness of rules, standards or practices (Codes), followed by the degree of Compliance with them. In many existing approaches this is as far as the assessment goes. However, the 6C approach goes on to consider two other important factors that can greatly escalate risk: Competence (the degree to which staff have the necessary skills and experience) and Culture, which refers to how supportive and mature the culture is for delivering risk controls. Set against this is the impact of Change on risk management, based on the degree to which the business environment is changing, and Complexity, the inherent intricacy of the business and its environment.

Our experience shows that pragmatic review against these six categories reveals a good understanding of vulnerabilities without detailed and time-consuming quantification.

Case study: identifying cultural vulnerabilities

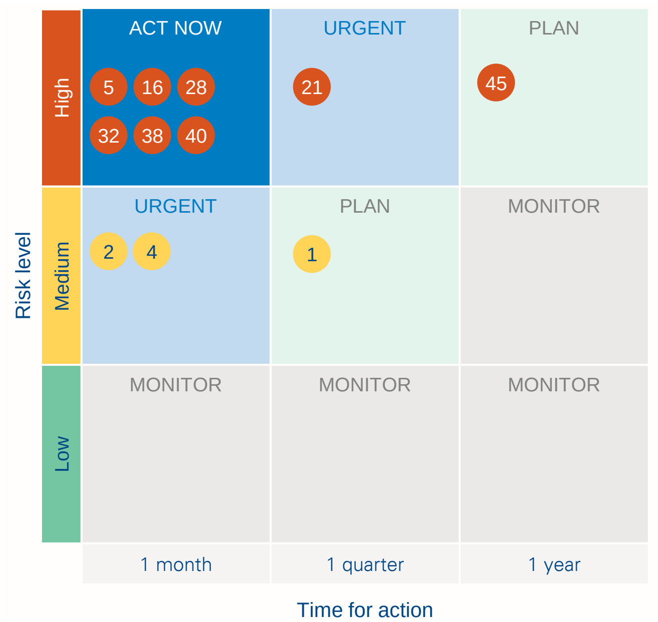


A national utilities operator had struggled to implement ERM effectively. We completed a 6C assessment of the operator's risk management arrangements and pinpointed cultural "risk denial" in reporting risks to the board, as it was viewed as a management failure to allow those risks to occur. We helped the operator introduce organizational incentives, championed by the CEO, which made risk a topic of conversation with the board and rewarded decision-making based on awareness of risk.

Facilitate decision-making

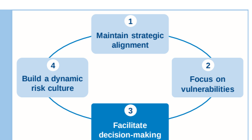
One of the most common shortfalls in ERM systems is that the mode of reporting to the executive or board does not lend itself well to making decisions. Risk reports often acquire a state of semi-permanence and end up as "wallpaper" behind more pressing top-management reporting information. This is a particular problem when situations are changing rapidly

One of the key features of the VBRM approach is therefore to ensure that top management has the right risk management reporting systems to enable rapid response and decision-making, in order to trigger actions that reduce risks before they materialize. This way, the links between strategy, execution and risk management controls remain close. This means designing reporting tools that are concise in how they summarize/aggregate risk data and tailored to organizational requirements. For example, the figure below links conventional rating of risk level (high/medium/low) with the time available to mitigate a risk before it materializes (in this case, during project execution).



A chart aggregating data across one or more dimensions can replace several charts – providing top management with a simplified means of rapid review of risk status.

Case study: board-level reporting of risks



A national rail infrastructure manager had a complex portfolio of risks, but no way of reporting these coherently to the board. Risks were presented in different formats with no ability to robustly prioritize investment decisions. We developed a method of translating different risks onto a single risk matrix, to better inform the board about the total risk profile and enable stronger risk-based investment decisions.

Build a dynamic risk culture

One of the most effective levers to ensure that a company's risk management approach is able to cope well with change and complexity is to focus on strengthening capabilities, culture and awareness. This provides the means to identify

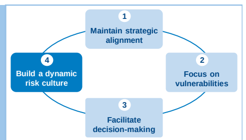
Arthur D Little

new and emerging risks, and to take the right actions to adapt management systems and processes rapidly in response.

Of course, culture change within any organization is difficult, and risk management culture change is no exception. However, the VBRM approach includes a number of measures, including providing a clear management path to excellence and engaging employees in pilot projects, to embed new practices.

Most importantly, a culture requires a key risk focus – such as a "burning platform" – as a key way to promote risk awareness and the importance of pragmatism and action-orientation.

Case study: improving incident investigation



A national infrastructure operator had an accident that revealed specific weaknesses in incident investigation. The operator publicized the accident as its "burning platform" and reissued its internal guidance. It identified resources across the business, who were given special training against the new guidance. The resources were released from normal duties for a period of time each week to run a pilot showcasing improved incident investigation techniques. The CEO released a webcast highlighting the recent accident as the reason for the initiative.

Insight for the Executive

This paper describes how conventional risk management approaches can be ineffective: they deal poorly with complexity, are slow to adapt to changing circumstances, and overemphasize reporting. In our work we have seen how these problems can be overcome with a more dynamic and focused approach to risk management. VBRM is such an approach, applied by companies irrespective of the ERM systems they already have. The essential elements of VBRM are:

- **Maintaining alignment of risk management with** changes in strategic direction. This requires establishing clear risk-based priorities and empowering risk owners to adapt management systems and processes as required.
- **Focusing risk management efforts on areas of vulnerability,** ensuring that risk management takes into account not only Compliance but also factors such as Competence, Culture, Complexity and Change (the 6Cs).
- **Designing risk-reporting systems that enable rapid top-management decision-making.** This should include specific risk data for key projects, provide concise summaries and include a ranking of urgency for action.
- **Building a dynamic risk culture through active involvement** in pilot projects, engaging the organization in progressive evolution towards excellence, and identifying a genuine burning platform that people understand and believe in.

The business world has moved on since ERM was first introduced. We think it is time for a change.

Authors

Stephen Watson and James Perry

www.adl.com/valuebasedrisk

A radical change in the consumption of energy in cities – The case of Spain

Substantial savings can be achieved in a decade

Executive Summary

Energy efficiency has been a hot topic for several years. It is one of the most important levers when improving the productivity of developed societies, as well as their environmental impact – a unit less of energy consumed for the same productive activity reduces not only costs, but also the pollution associated with it. For many countries that depend strongly on energy imports, it also impacts the commercial trade balance.

Many administrations have been putting forward measures to pursue such efficiency – the EU's 20/20/20 targets[1] and the North American Climate, Clean Energy, and Environment Partnership Action Plan[2] are examples. Most of these objectives are, however, at national or international level. In this viewpoint, we take a different angle and look at the cities. Our rationale is threefold: (i) there is a growing trend towards urbanization across the world, with 66 percent of the population expected to live in cities by 2050, versus 54 percent today[3], (ii) many of the actions required to improve energy efficiency can be influenced by local administrations, and (iii) cities are most affected by air pollution and transport congestion, and hence the impact of these measures is particularly beneficial to them.

Arthur D. Little has been analyzing the situation and the potential for energy efficiency in the 15 largest cities in Spain – from Madrid and Barcelona (which both have more than 1 million inhabitants) down to Vigo and Gijón (at 200,000 inhabitants). Overall, the analysis concludes that circa 40 percent reduction in consumption could be achieved in the coming decade with measures that make economic, technical and social sense, and that would also offer areas of opportunity in all sub-sectors.

- In terms of economic impact, it would reduce the energy bill of the citizens, businesses and public services in these cities by 37 percent[4], or €3.4 billion annually.
- In terms of environment and quality of air, such a reduction would reduce CO2 emissions by 18.8 million tons –30 percent[5] of the target in 2030 for the non-ETS sectors in Spain – and ppm concentrations by 25 percent.
- In terms of investment, improving the energy efficiency of buildings and reducing the energy needs of urban transport would require an investment of circa €11bn over the next 10 years.

1 European Commission, "2020 climate & energy package"
2 The White House, Office of the Press Secretary
3 United Nations, "World Urbanization Prospects"
4 Arthur D. Little Analysis
5 European Commission

We have calculated an index on energy efficiency for each city, based on their ranks along 11 indicators associated with the key drivers for each sector. Overall, the city of Bilbao ranks the best, with Zaragoza a close second. There is no apparent relationship between the size of the city and its energy efficiency index performance – the largest cities, Madrid and Barcelona, are ranked in the middle of the table. Leadership on each of the 11 indicators is spread among the 15 cities. Almost all cities are positioned among the top five in at least one indicator, and even the cities with the overall best performances are ranked among the worst in some indicators. The potential for improvement is real.

Such results highlight two broad conclusions, in our view. First, in the context of ongoing smart-cities discussions, this is a call for city and regional authorities to align their priorities through comprehensive energy efficiency policies, either stand-alone or embedded in broader programs. This is indispensable as these authorities can heavily influence many of the measures to be taken. Secondly, there are many opportunities to be captured. Investments in infrastructure and equipment, as well as services that provide opportunities for the related players, are needed – from energy companies, equipment manufacturers, engineering firms, automobile OEMs and others that are willing to engage in city strategies.

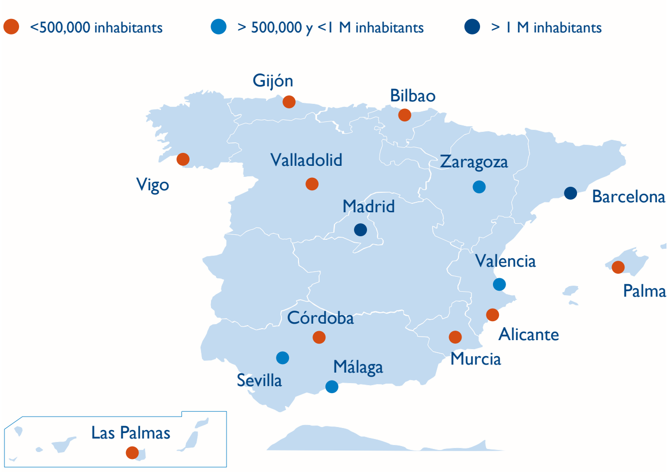
1. Energy consumption in Spain's cities

The need for a local approach to energy consumption

Until today, most of the policies implemented to tackle the world's energy and environmental challenges have been designed at national or even international levels. Examples include the EU Emission Trading Scheme, renewable subsidies in most developed countries and national incentives to buy electric vehicles. While these policies have undoubtedly changed the energy landscape in many countries, they fail to address the specific energy challenges and opportunities cities face in a comprehensive way. Unveiling the full potential for enhanced energy performance at city level requires local policies to accompany global ones: adequate urban planning, efficient public transport systems and effective traffic management have the potential to greatly reduce urban energy consumption and carbon footprint. These are all local policies, not global.

In order to understand such potential and efficiencies at city level we have analyzed, compared and estimated the reduction potential of energy consumption in Spain's 15 largest cities.

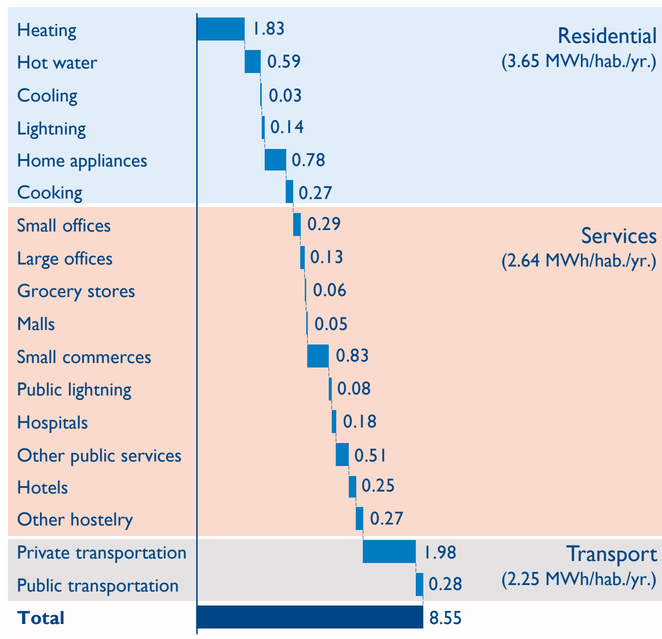
Figure 1: Spain's largest 15 cities



Breakdown of cities' energy consumption

The 15 largest cities in Spain account for 90.2 TWh[6] of energy consumption, or 18 percent[7] of the country's total. It represents 8.55 MWh per inhabitant per year on average. This energy is consumed as follows:

Figure 2: Energy consumption at the average Spanish city by sub-sector (MWh/inhabitant/year)



Source: Arthur D. Little

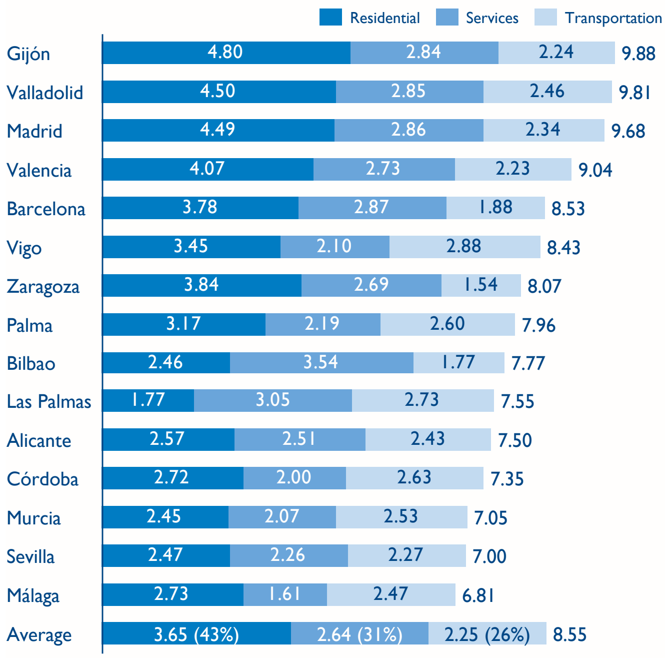
- Residences account for 43 percent of all consumption, or 38.5 TWh (8.9 MWh per household per year), of which 17.6 TWh is electricity and 15.0 TWh is gas. Of this, 50 percent is spent on heating, and the rest on lighting, home appliances, cooking, water heating and air conditioning.
- The service sector represents 31 percent of consumption, or 27.9 TWh (82 kWh per square meter of commercial surface per year). Within the service sector there are many sub-sectors, including retail services and offices, public administration buildings and services, and hospitality.
- The remaining 26 percent is transportation. Of the 23.82 TWh consumed in these activities, 22.5 TWh is diesel and gasoline, 0.5 TWh is natural gas and 0.8 TWh is electricity, with the remaining 0.02 TWh being LPG. Eighty-eight percent of the consumption is in private transportation, while

6 Minetur, *"Estadística de la Indústria de la energía eléctrica," "Estadística de la industria del Gas Natural," "Estadística de la industria del GLP"; Cores, "Consumo de crudo y productos petrolíferos por sectores económicos,"* Arthur D. Little analysis

7 Excluding industrial energy consumption

public transportation represents 12 percent of the total. On average, each citizen consumes 2.25 MWh per year for urban transport.

Figure 3: Energy consumption by sector (MWh/hab.)



Source: Arthur D. Little analysis

Key indicators and energy index to compare

In order to compare the situation among the different cities, we have calculated an index of their energy usage. The index takes into account not only actual energy consumption, but also how efficient that consumption is and its degree of commitment to a sustainable urban model.

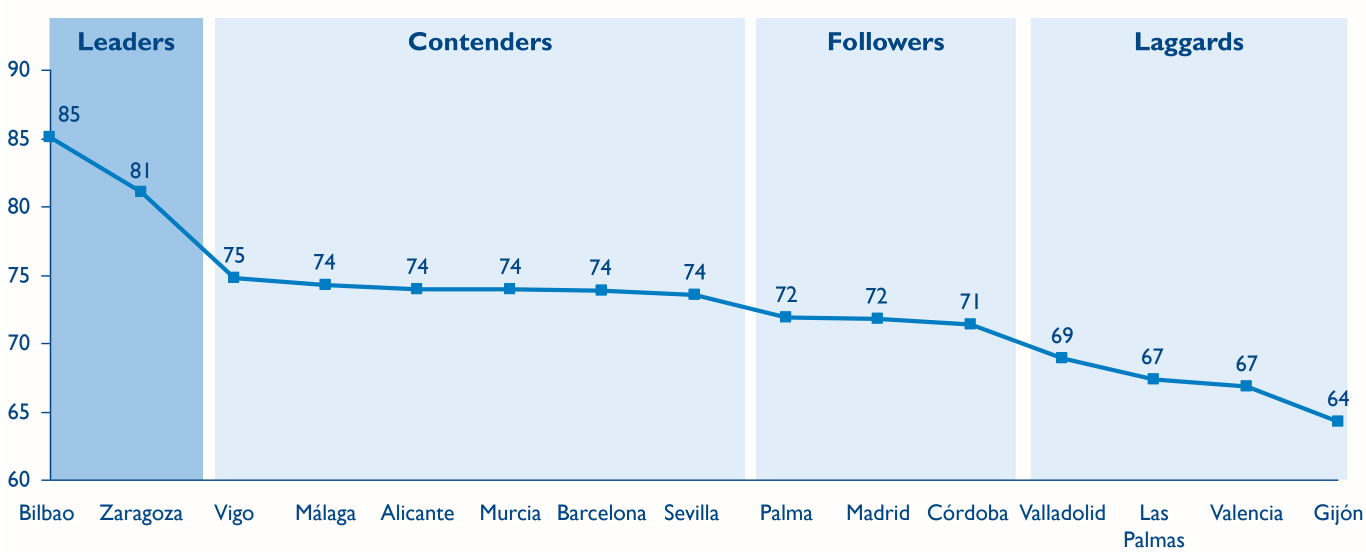
It is built upon 11 indicators that are weighted by relevance. Six of these are related to the transportation sector; they include the modal mix of transportation (public versus private, fuel consuming or not), the penetration of electric vehicles (EVs), the availability of infrastructure for EVs, the efficiency of the public transportation fleet and the share of non-diesel-fueled buses, as well as the overall consumption. All of this is publicly available information or can be estimated at city level.

Three indicators relate to the residential sector. These include the share of homes that do not comply with the existing technical norms of the residential buildings (see more detail in the next section), the percentage of homes holding energy certificates and the actual consumption per home. Information on these is also available in each city or can be estimated.

Two more indicators refer to the service sector performance. This is the sector with least availability of relevant public data. Some cities have started to publish similar certifications of buildings in the residential segment, but there is clearly room for better transparency in this important sector. The indicators used are more aggregate: consumption per 100 square meters of surface in the sector, and consumption per 1,000€ of value added.

The index grants a score to cities ranging from 1 to 100. A theoretical city with a score of 100 would be the leading city in all 11 indicators. Some of the indicators have been normalized to compare cities in equal terms. For instance, considering that in Spain there are sixteen climate areas according to the severity of winter and summer, heating consumption has been adjusted to normalize conditions among cities belonging to different areas. (See separate box for methodology in the annex.)

Figure 4: Efficiency Index Ranking of Spain's 15 largest cities



Results

Figure 4 shows how cities rank in terms of our index of energy efficiency.

The index ranking shows two clear leaders, Bilbao and Zaragoza, a large group of contenders and followers with intermediate rankings, and a final group of laggards. The difference between the first and the last group is substantial and already indicates the potential for doing things differently.

We find that there is no apparent relationship between size of the city and energy efficiency index performance – the two largest cities, Madrid and Barcelona, are ranked in the middle of the table.

Nevertheless, as Figure 5 shows, leadership on each of the 11 indicators is spread among the 15 cities. Almost all cities are in the top five in at least one indicator. On the other hand, even the cities with overall best performances are ranked among the worst in some indicators:

- Zaragoza is the city with the lowest consumption per capita in the transport sector, due to the limited use of the private vehicle as a means of transport – only 34 percent[8] of urban trips – whereas Vigo is the city with the higher consumption per capita, with 69 percent of trips made by private vehicles.
- Bilbao is the clear leader in terms of EV penetration, although even in this city EVs are still testimonial, with a penetration of 0.23 percent[9].
- In terms of charging infrastructure for EVs, Barcelona emerges as the city with the higher investment in electric charging points (10 charging stations per 100,000 inhabitants).
- Regarding the fuel efficiency of public buses, Valladolid has the most energy-efficient fleet, due to its large share of buses fueled by LPG. The presence of electric buses is still testimonial in most cities.
- As shown in Figure 7, climatic conditions, particularly winter severity, have a direct impact on heating consumption. Cities located in the most severe climatic zones consume around 3.5 times more energy in heating in comparison to cities in the mildest regions.
- As shown in Figure 6, once heating consumption is normalized, we find that the residential sector in Bilbao shows the lowest energy consumption, with 5.0 MWh per household per year, while Valencia shows the highest consumption and almost doubles that of Bilbao, with 9.7 MWh per year.

Figure 5: Comparative of city performance by indicator

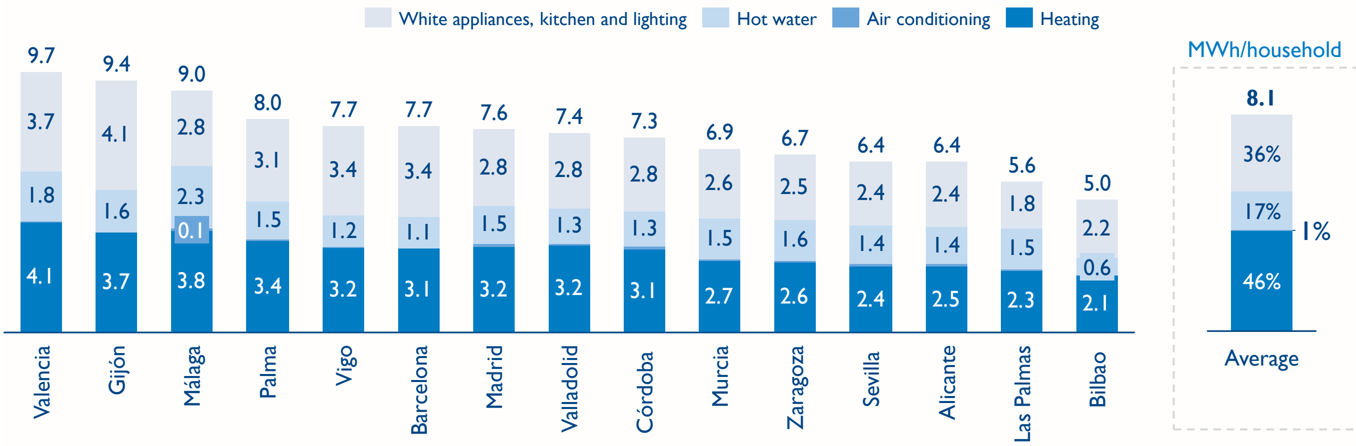
	Energy efficiency index	Transport consumption (MWh/hab.)	Share of car trips (%)	Penetration Electric vehicle (%)	E.V. chargers (#/100.000 hab.)	Bus fleet fuel efficiency (MWh/100km)	Share of buses other than diesel (%)	Consumption per residence (MWh/home)	Share of homes EFG (%)	Share of certificated homes (%)	Consumption services (kWh/100m²)	Intensity services (kWh/1,000€)
Bilbao	85.1	1.8	42	2.3	2.0	499	72	5.0	90	3.3	55	289
Zaragoza	81.0	1.5	35	0.7	3.2	461	100	6.7	82	1.7	68	256
Vigo	74.7	2.9	70	0.2	3.4	582	100	7.7	79	3.6	62	223
Málaga	74.3	2.5	60	0.2	1.2	477	60	9.0	88	4.8	51	214
Alicante	73.9	2.4	60	0.2	2.7	499	70	6.4	90	11.0	62	290
Murcia	73.9	2.5	64	0.1	4.3	582	100	6.9	93	5.1	58	255
Barcelona	73.8	1.9	31	0.3	10.0	493	50	7.7	90	11.6	99	248
Sevilla	73.6	2.3	55	0.8	6.2	522	100	6.4	88	4.8	94	251
Palma	71.9	2.6	61	0.1	6.2	475	10	8.0	89	6.7	57	248
Madrid	71.7	2.3	41	0.5	2.6	522	100	7.6	79	7.8	111	237
Córdoba	71.3	2.6	64	0.5	2.1	455	10	7.3	88	4.8	64	233
Valladolid	68.8	2.5	60	0.1	5.6	387	100	7.4	81	4.3	119	271
Las Palmas	67.3	2.7	65	0.1	2.9	499	70	5.6	90	6.7	96	360
Valencia	66.8	2.2	54	0.2	2.3	483	20	9.7	90	11.0	68	280
Gijón	64.2	2.2	55	0.1	3.6	467	0	9.4	83	1.9	86	284

Ranking position 1-5 | Position 6-10 | Position 11-15

Source: Arthur D. Little analysis

8 Eurostat
9 Dirección General de Tráfico, Arthur D. Little analysis

Figure 6: Breakdown of normalized energy consumption in the residential sector for each city analyzed

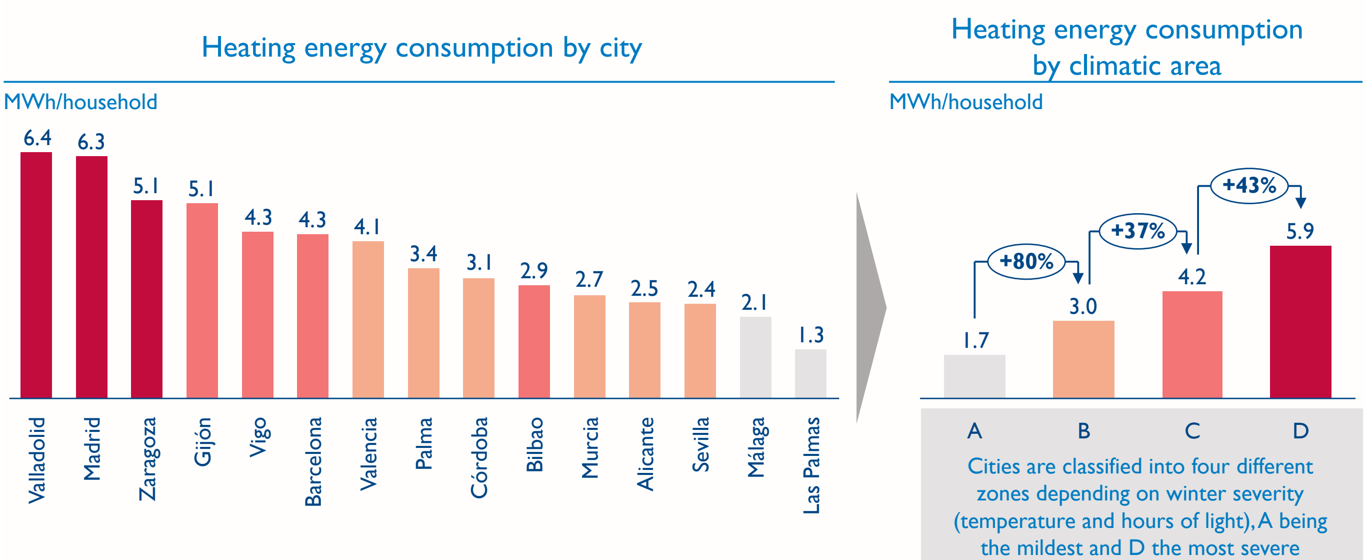


Source: Arthur D. Little analysis

- In terms of share of non-compliant homes (E, F or G certificate level), Vigo, Madrid and Valladolid are the best.
- In the service sector, Malaga scores best on both indicators (energy consumption and energy intensity), while Valladolid and Las Palmas show the worst performances.

Overall, the situation indicates that a great deal of improvement is possible and that all the cities sampled have areas of opportunity.

Figure 7: Relationship between heating energy consumption and climatic conditions



Source: Arthur D. Little analysis

2. The potential for energy efficiency

There are several ways to assess the potential for energy savings, depending on how different factors are taken into account: (i) absolute activity and mix, since potential savings depend on the evolution of absolute magnitudes, such as economic activity and population; (ii) technological impact and cost, since savings can be calculated on the basis of the currently available technologies or considering the expected technological evolution; (iii) time frame, since the longer it is, the higher the potential for efficiency gains and the more uncertain the results; and (iv) economics, as there are many different ways to achieve energy savings, but not all of them are profitable today.

In our analysis we have taken the following approach: (1) all improvements are based on volumes of activity per city and sub-sector, *ceteris paribus*, in 2015; (2) only currently available technologies are considered according to their existing improvement potential; (3) a decade is considered the time frame – long enough to allow for public policy to be defined and implemented, and short enough for forecasts to be meaningful; (4) we have considered profitable investments only, as defined by current energy prices and technological costs.

This implies that our estimates are conservative, opting for a more realistic – although still substantial – ambition so it can be achieved in a manageable time frame.

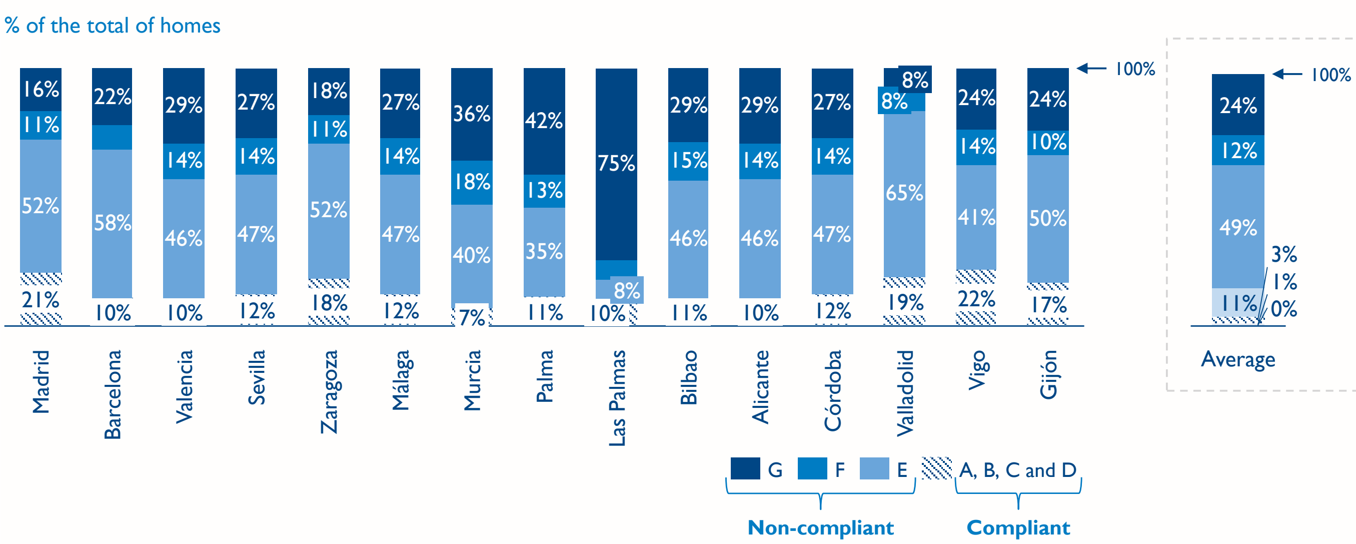
Residential sector

Since 2006 there has been a technical construction norm and an appraisal required for all residential buildings, which indicates, among other things, its energy efficiency. Compliant buildings are ranked from A (best) to D (worst) according to the quality of insulation and their use of adequate heating, cooling and lighting technologies. Beyond D, grades E, F, and G indicate progressively worse degrees of non-compliance with the existing norm. In Spain's 15 largest cities, 87 percent[10] of residential buildings are estimated to be non-compliant. (See Figure 8 for the percentage in each of the analyzed cities.)

Optimization of consumption to levels that are compliant, without resorting to full reforms, are well known. They include condensation gas and low-temperature boilers, better insulating materials and elements, self-supply applications, LED and low-consumption lightning, and solar and condensation water heating. Most of these measures are self-financing and only require substitution of existing, less-efficient equipment.

The potential for improvement is substantial. Only applying readily available, self-financing measures (within three to five years) to homes in the worst conditions (non-compliant with existing building standards – 86 percent of the total) can yield a reduction of 40 percent of the total energy consumption in the

Figure 8: Distribution of homes according to their energy efficiency certificate (% of total)



10 Regional registers for energy certificates

residential sector, from 3.65 MWh to 2.19 MWh per home per year.

Note that there are many more measures that can play roles in this segment, but these have not been included in our estimates: there are measures that imply refurbishment or better design of the buildings, but these typically take longer that our time frame. There are other measures that are harder to quantify but nevertheless significant, such as substitution of appliances for more efficient ones and improvement of efficiency on already-compliant buildings (those in the A to D range).

The service sector

The service sector encompasses a wide variety of sub-segments. It includes large hospitals and shopping centers, as well as public buildings, street lighting, smaller offices, retailers and hospitality. The bulk of consumption is centered on smaller offices, restaurants, bars and other businesses.

The measures needed to optimize energy consumption in these segments are well known and available too. For larger buildings, whether these are hospitals, public services or commercial buildings, these measures encompass heating/cooling and power co-generation, managed efficient lighting and climate, renewable-based self-supply and others. For smaller premises, measures are similar to those of the residential segment: use of more efficient heating and cooling systems, insulation improvements, etc. These measures are self-financing in most cases, and numerous engineering firms, installers and utilities facilitate the set-up of energy service companies (ESCOs) to optimize the consumption.

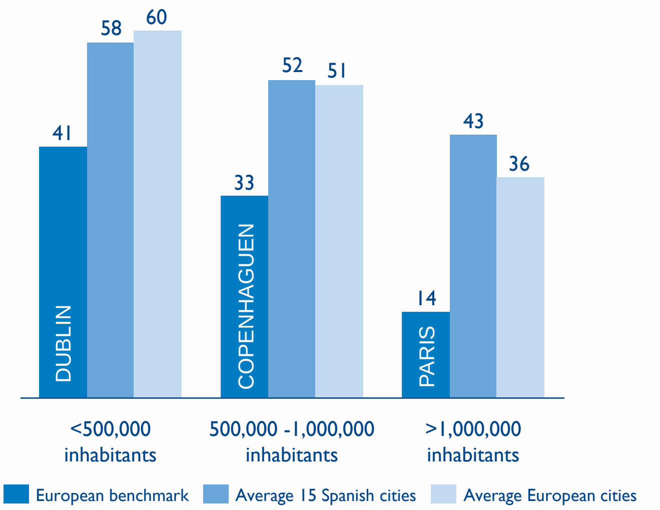
Some of the cities have also started to measure the efficiency of the services segment in a certifying system analogous to the one used in the residential segment. Only Barcelona and Valladolid publish their situations, which show that 45 percent of the services buildings in both cities are non-compliant.

The potential for improvement is important in most sub-sectors. By applying self-financing, readily available solutions exclusively, energy use can be reduced by 30–35 percent in shopping centers and hotels and 45-55 percent in hospitals[11]. A weighted average of these would yield an overall 41 percent reduction of energy use in the service sector, from 82 kWh to 48 kWh per square meter per year.

The transportation sector

The transportation sector in cities has several levers that are relevant to its energy efficiency. The first and foremost is the modal mix. Our sample includes cities with comparatively low rates of private vehicle usage (Barcelona, with 31 percent, is the best performer in the group), and cities where private vehicles account for an overwhelming majority of trips (Vigo, 69.9 percent). Several reasons might explain wide differences, such as city density, size, topography or infrastructure, and local customs and attitudes towards walking or using bicycles, for example. However, a comparison with other similar-sized European cities reveals a substantial potential for improvement, as shown in Figure 9.

Figure 9: Modal mix comparison against European cities and potential for improvement (% of private transportation)



Source: Arthur D. Little analysis

Public transportation represents 12 percent of the total sector consumption. The consumption of energy is mainly driven by the type of engines of public buses and the fuel they consume. Our analyses indicate that although Spanish cities have been experimenting with alternative fuels for some time, there is substantial room for improvement. Electric buses, for instance, have only been modestly introduced. (Madrid, the leading city in this aspect, has only 20 electric buses out of a total of 1,903.)

Private transportation represents most of the energy consumption in this sector at city level, and nearly 100 percent of consumption is either diesel or gasoline; EV penetration is still at an incipient level. Only 2,342 electric vehicles were sold in Spain in 2015, 0.23 percent of the 1,034,232 vehicles sold in 2015. This is a large difference from the 9.6 percent of EV sales versus the total in the Netherlands or the 22 percent in Norway.

Overall, in the transportation sector, 27 percent of energy use can be avoided if the modal mix can be optimized to close half of the gap with European peers, public bus systems are electrified and about 1 million private EVs are on the Spanish roads (a 4 percent penetration over a current fleet of 27.95 million). This would represent a reduction in the energy consumed for urban transportation from 2.25 MWh to 1.65 MWh per inhabitant per year.

11 GTR: *"Estrategia para la rehabilitación – claves para transformar elsector de la edificación en España 2014"*

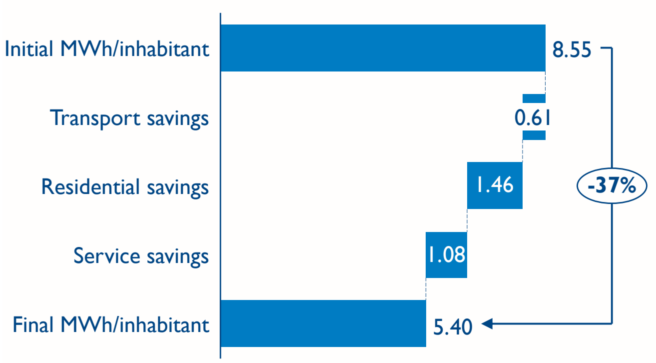
3. The implications of more efficient use of energy in Spain's largest cities

As indicated at the beginning of this viewpoint, the absolute potential for energy efficiency can go far beyond what we are considering if longer time frames or better and more efficient technologies are considered.

Within our self-imposed boundaries of a decade, existing technologies and self-financing solutions, our analysis concludes that achieving energy savings of around 40 percent on a per-capita basis is realistic in Spain's 15 largest cities.

This reduction amounts to 33.2 TWh, or the equivalent of the annual aggregated consumption of the cities of Córdoba, Vigo, Alicante, Las Palmas, Gijón, Bilbao, Valladolid, Palma, Murcia and Málaga.

Figure 10: Potential energy savings by sector



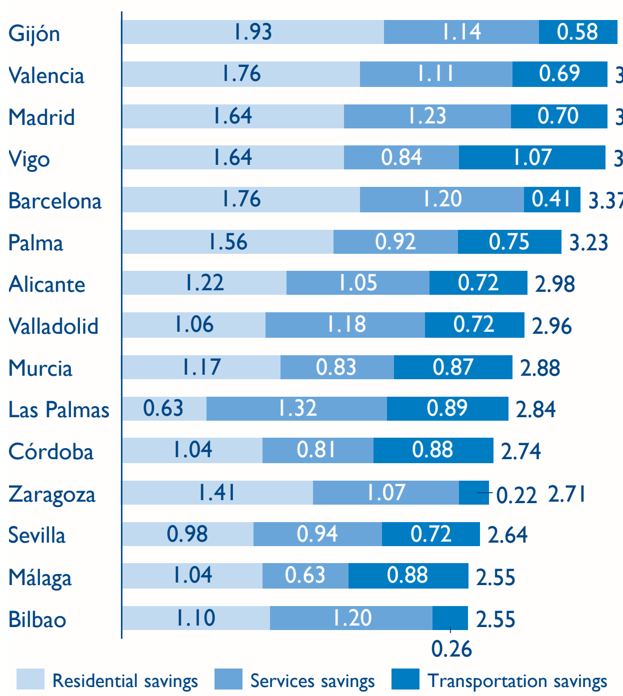
Source: Arthur D. Little

As Figure 10 shows, the main contributor to these savings would be the residential sector, due to the obsolete state of the Spanish stock of residential buildings. Within this sector, around 80 percent of the savings would be on heating, achieved by replacing inefficient heating systems with more advanced systems – such as low-temperature boilers – or by improving the insulation of households. Within the service sector, around 60 percent of these savings would also be obtained by improving the efficiency of heating and air conditioning systems and improving the insulation of buildings. The remaining 40 percent of savings within the service sector would mostly be obtained from lighting improvements – particularly relevant in offices and commercial centers – and efficiency gains in hot-water systems, which would be especially relevant for hotels and hospitals. In the transport sector, the modal shift towards a lower use of the private vehicle would represent 63 percent of the savings, whereas the penetration of the electric vehicle would account for 27 percent of the reduction in energy consumption. The electrification of public buses would represent 10 percent of the savings potential within the sector.

Going down to the city level, as Figure 11 shows, the amount of potential savings, as well as how these are distributed across sectors, vary by city. We find that Gijón, the least efficient city according to our index, is also the city with the highest potential for energy savings, as it has a large share of buildings that are not compliant with existing energy standards and the modal mix is dominated by the private vehicle.

Nevertheless, in any city there are large efficiencies to be captured, which would have profound economic, environmental and social implications.

Figure 11: Energy savings by sector and city (MWh/hab.)



Source: Arthur D. Little

Economically, the implied measures would reduce the energy bill for consumers by €3.4bn every year. As Figure 12 shows, the investment required to capture these efficiencies would be of the order of €11bn, without taking into account the acquisition of private electric vehicles.

Environmentally speaking, it would reduce CO2 emissions by 18.8 million tons, which, excluding the heavy industry, represents 30 percent of the reduction target for Spain in 2030.

Socially, these energy savings, on top of the cost reduction, would reduce atmospheric particulate-matter concentration levels in Spanish cities, especially those related to the transport sector. According to the World Health Organization, air pollution is responsible for the deaths of 6,800 citizens every year in Spain. We estimate that a more efficient transport sector would reduce ppm concentration levels in Spanish cities by 25 percent.

Capturing those efficiencies requires two sets of actions from different types of actors: administrations, both local and regional, and the private sector.

Figure 12: Investment needs by sector

		Description / estimate	Approximate investment
Transport	Modal shift	Calculated considering the cost of the buses needed incrementally to accommodate the shifting demand from private transport to public transport	1,100 M€
	Electric buses	Calculated taking into account the cost of electrifying the fleet of public buses	3,200 M€
	Electric vehicle	Calculated considering the public charging infrastructure needed, assuming a ratio of electric vehicles per charging point equal to the European average	400 M€
Residential		Mix of different investments required – boilers, lightning, insulation – with 4-year payback	4,000 M€
Services		Mix of investments in small offices, restaurants, bars, small retail and large buildings (public and private)	2,300 M€
Total investment			**11,000 M€**

Source: Arthur D. Little analysis

Barriers to change and how to circumvent them

For most cities and companies there is a great challenge ahead, and it will require a leap forward from all stakeholders. The gains to be made by all of them – from local administrations to private companies and citizens – are vast, and it is worth the effort.

There are several aspects that constitute a barrier to change, and these need to be addressed in order for the leap forward to take place.

In the residential sector, for instance, most of the potential for change lies in the hands of a large number of private homeowners. For many individuals and families, energy savings are often not high priority since energy does not take a big share of their budgets. Also, residential measures often imply reforms and construction, which can have a high cost and a negative impact in daily activities. Therefore, if the change is to happen, bold political action is needed.

Similarly, in the services sector, barriers lie in the low priority many landowners give to energy efficiency. Policies can be applied to accelerate the rate of change. These can range from communication to increased requirements for commercial licenses or changes in local tax policies.

Lastly, in transport, the biggest barriers lie in the lifestyle of a big share of the population which relies heavily on the private vehicle for their daily activities. The reason for this is manifold. For instance, the layout of modern cities, with extended suburban areas, makes it unfeasible for many to abandon the private vehicle. Also, public transport is far from universal in many places or its design is suboptimal, making some trips unreasonably long. From this starting point, cities can encourage the change in many ways: investing directly in greener and more accessible public transport, pursuing educational measures for the promotion of EVs, enacting positive reinforcement measures such as free parking for greener vehicles, or establishing punitive policies such as traffic restrictions.

For local and regional administrations there are many lines of action that will influence the pursuit of the discussed outcomes:

- First of all, local administrations must include ambitions and objectives which are aligned to the aforementioned. Many of the cities sampled have plans and emerging initiatives to tackle some of these aspects, and emerging initiatives are in place to act. Others are pursuing efficiency as part of broader clean-air or smart-city initiatives. Few, however, have structured programs with appropriate prioritization according to the impact to be achieved.
- There is a clear need to have more transparency and better data on the actual performance. Some of these cities have their own indicators and others are available regionally or nationally, but as with anything that needs to be transformed, it should be measured with certain granularity, and in many key segments this is not the case today.
- There is also a need for combined and coordinated policies to overcome market failures. There are many market failures which act as barriers to achieving these efficiencies that need to be addressed.
- Coordination with the private sector is to be envisaged by local and regional administrations. Energy companies, equipment manufacturers and many other service providers already have technologies to make these changes happen, and there is capital available to be invested if the adequate framework can be put in place.

Local administrations can take leadership on their own or facilitate the formation of consortia with the private sector to pursue such a transition to a more efficient, lower carbon footprint and better quality of life for their citizens. Many different ways of getting organized are possible, and examples of such initiatives exist worldwide.

From the private sector, this transition will require investments in equipment and infrastructure – from installation of electric vehicle chargers in public spaces to replacement of obsolete heating systems with more efficient technologies – and many types of services, thus creating opportunities for energy companies, equipment manufacturers, engineering firms, automobile OEMs and other players. However, this requires active engagement with city authorities and specific strategies:

- Adequate levels of communication with city authorities. Many energy companies and equipment manufacturers have their own regulation departments, but these are typically focused on the relevant ministries and in nation-wide legislation. Building the appropriate level of communication with key cities requires a different approach.
- Organize for city strategies. In the end, cities are a different customer segment and, as such, it requires organizing marketing, sales and delivery teams in a way that recognizes it.
- Develop solutions and integrated packages to tackle city needs. These can take different forms – ESCOs, partnerships with other key players – to provide integrated solutions or other options.
- And finally, an overall effort to position the company vis-à-vis cities.

At Arthur D. Little, we have accompanied and helped local administrations and private players making bold decisions to tackle such challenges. While not easy or straightforward, these strategies are feasible and worth the effort.

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4. Annex: Index calculation methodology

The energy efficiency index is composed of 11 indicators, as described in Figure 13.

Figure 13: Indicators used for the index

Sector	Indicator	Description	Weight
Transportation	01	Energy consumption in urban transport (MWh/hab./yr.)	13.5%
Transportation	02	Share or urban displacements in private vehicles (%)	2.7%
Transportation	03	Penetration of electric vehicles (%)	2.7%
Transportation	04	Number of electric cars per 100.000 inhabitants	2.7%
Transportation	05	Average consumption of bus fleet (MWh/100km)	2.7%
Transportation	06	Share of buses running on fuels other than diesel	2.7%
Residential	07	Normalized energy consumption (MWh/household/yr.)	21.0%
Residential	08	Share of households non-compliant with building standards	18.9%
Residential	09	Share of households holding an energy certificate	2.1%
Services	10	Energy consumption service sector (kWh/100m2/yr.)	15.5%
Services	11	Energy intensity service sector (kWh/1000€ GDP)	15.5%

Source: Arthur D. Little analysis

The index takes into account not only actual energy consumption, as shown by indicators 1, 7 and 10 but also how efficient that consumption is, as shown, for instance, by indicators 2, 5, 8 and 11. Indicators 3, 4 and 6 represent the degree of compromise with a sustainable urban model.

Every city has been awarded a score for each indicator. This score ranks from 0 to 100, with 100 being the score for the best-performing city in the sample and 0 for the worst. For instance, as shown in figure 14, Bilbao has the highest E.V. penetration and the lowest normalized household consumption, with a 100 score in both indicators. On the other hand, its number of certified households is one of the lowest at 3.3%, so its score on that indicator is very low.

In order to calculate a unique energy index for every city, different weights have been attributed to each indicator, according to the following criteria:

- The sum of the weights of all indicators belonging to one sector (transport, residential, services) matches the weight that the particular sector has over total consumption. That is, the sum of the six indicators of transport amount to 27 percent of the total index weight. The same happens in residential and services, with 42 percent and 31 percent, respectively.
- Within transport and residential, most of the weight has been given to actual consumption, as it is the most objective measure for comparison. That is, indicators 1 and 7.
- In services, the actual consumption and the energy intensity are equally weighted (15.5 percent each).

The contribution of each indicator to the index of a particular city comes from multiplying the weight of each indicator (common to all cities) and its respective score (specific for each city). The sum of the contributions from each indicator results in the final efficiency index for each city.

Figure 14. Example of index calculation for some cities

Sector	Indicator	Bilbao Value	Bilbao Score	Bilbao Index	Zaragoza Value	Zaragoza Score	Zaragoza Index
Transportation	01 Transport consumption	1.8	87	11.8	1.5	100	13.5
Transportation	02 Modal mix	32.0	73	2.0	34.7	88	2.4
Transportation	03 E. V. Penetration	0.23	100	2.7	0.07	29	0.8
Transportation	04 E. V. chargers	2.0	20	0.5	3.2	32	0.9
Transportation	05 Bus fleet efficiency	499.3	77	2.1	461.2	84	2.3
Transportation	06 Share of non-diesel buses	72	72	1.9	100	100	2.7
Residential	07 Household consumption	5.0	100	21.0	6.7	74	15.6
Residential	08 Non-compliant households	89.5	88	16.6	81.6	96	18.2
Residential	09 Certified households	3.3	29	0.6	1.7	14	0.3
Services	10 Services consumption	55	93	14.4	68	74	11.5
Services	11 Energy intensity	289.2	74	11.5	256.4	83	12.9
	Efficiency Index			85.1			81.0

Sector	Indicator	Barcelona Value	Barcelona Score	Barcelona Index	Madrid Value	Madrid Score	Madrid Index
Transportation	01 Transport consumption	1.9	82	11.0	2.3	66	8.9
Transportation	02 Modal mix	30.6	100	2.7	41.0	75	2.0
Transportation	03 E. V. Penetration	0.03	12	0.3	0.05	12	0.5
Transportation	04 E. V. chargers	10.0	100	2.7	2.6	26	0.7
Transportation	05 Bus fleet efficiency	492.7	78	2.1	521.7	74	2.0
Transportation	06 Share of non-diesel buses	50	49	1.3	100	100	2.7
Residential	07 Household consumption	7.7	64	13.5	7.6	65	13.7
Residential	08 Non-compliant households	89.7	88	16.5	79.4	99	18.7
Residential	09 Certified households	11.6	100	2.1	7.8	68	1.4
Services	10 Services consumption	99	52	8.0	111	46	7.1
Services	11 Energy intensity	247.6	86	13.4	237.3	90	14.0
	Efficiency Index			73.8			71.7


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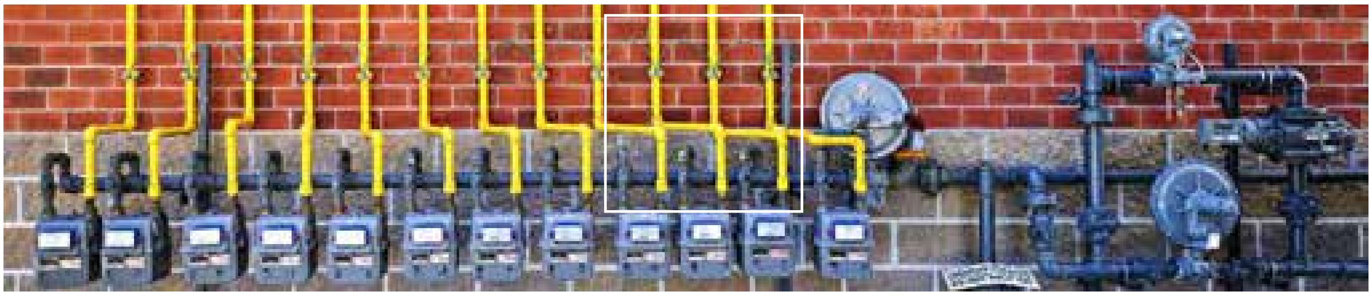
Italian gas distribution tenders

An opportunity for utilities companies and infrastructure funds

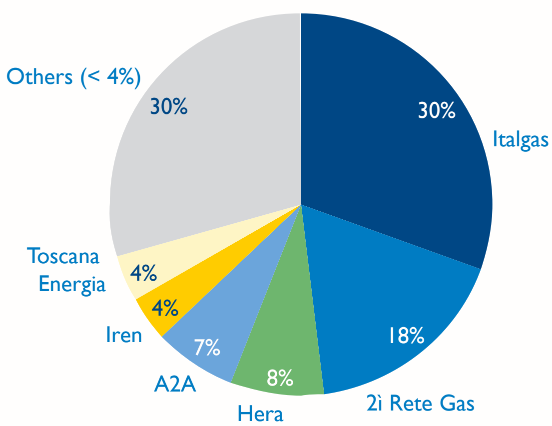


The Italian gas distribution sector is expected to face a new tender season in the short to medium term. All the concessions in the country have been bundled together in order to create ATEMs, concessions larger than the average DSO size. Each ATEM will be awarded after a tendering process. Utilities as well as infrastructure funds thus have a window of opportunity to invest in the Italian market, which is undergoing a consolidation process.

The Italian gas distribution sector

The Italian gas distribution sector is highly fragmented: the top six DSOs represent ~70% of the existing **22 million delivery points** (DPs), while the remaining 30% is split among more than **200 players**.

Market share (#DPs)



Source: Arthur D. Little analysis on MSE and AEEGSI data

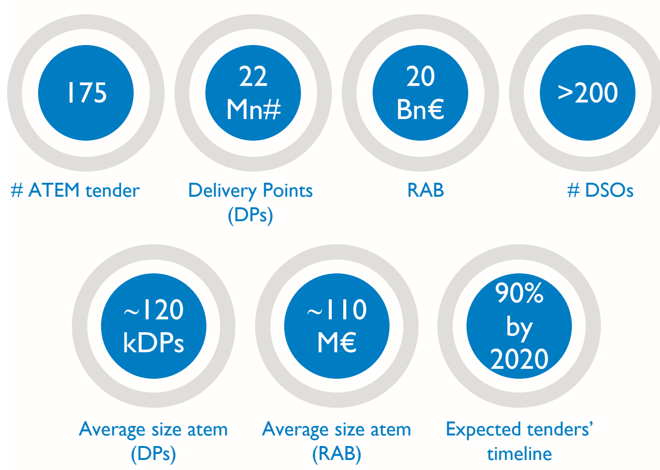
In order to increase companies' efficiency and improve the quality of service delivered, the government decided that consolidation of the sector was required. It introduced the ATEM **concept**: ministerial decree 226/2011 divided the Italian territory into **175 ATEMs** ("minimum concession area") for the next tenders and defined an ATEM tender calendar.

The size of an average ATEM is around 120,000 DPs, 20% more than DSOs' average size (~100,000 DPs).

Few operators are likely to have all of the technical and financial capabilities to be competitive in the upcoming ATEM tenders. (E.g., bidders should manage at least 50% of ATEM DPs to participate to the tender.)

On the other hand, in the majority of ATEMs (~70%), the **first DSO** ("incumbent") **manages more than 50% of DPs**. Market share represents one of the main entry barriers for future tenders: the greater the incumbent's capabilities and willingness to retain the ATEM, the lower the ATEM's contestability.

Key numbers



Source: Arthur D. Little analysis on MSE and AEEGSI data

The **total value of the Regulatory Asset Base (RAB)** that will be renegotiated through ATEM tenders is estimated at around **€20 billion** (about €110 million per ATEM).

This scenario will impact the market in two main ways:

- The number of active operators is expected to decrease sharply after the next round of tenders.
- Several operators will be looking for financial and industrial partners to increase their likelihood of success.

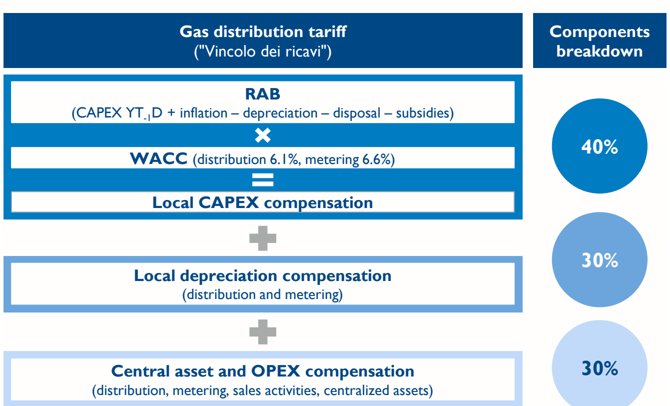
The Italian regulatory framework…

The gas distribution concessions' regulatory framework – recently completed by the regulator and the Ministry of Economic Development (MSE) – is based on the following pillars:

- Clear rules for **tariff calculation**: six years regulatory period (ending 2019) and asymmetric regulation to increase competition
- **A standardized tender process** (DM 226/11) in terms of technical and financial requirements, awarding criteria, offer structure and employment safeguard clause
- A defined **tender timeline**: the first round of ATEM tenders has already started – with some delay
- **Standard guidelines** to calculate outgoing DSOs' asset reimbursement values ("VIR") when not otherwise specified in concession agreements

The current **tariff calculation** model is based on parametric remuneration of OPEX/central assets and allowed return for local distribution and metering assets (RAB).

Revenues model



Source: Arthur D. Little analysis on MSE and AEEGSI data

The regulatory period for the WACC will last six years, in place until the end of 2021, with a mid-review effective in 2019.

To create more intense competition in the bidding process, the authority introduced an **"asymmetric regulation"** in the definition of the tariff rules that are applicable to the new ATEM concessions:

- For the share of ATEM acquired from outgoing DSOs, tariffs will be calculated on the basis of the VIR effectively paid (instead of the RAB previously recognized for the municipalities within the ATEMs): "real money spent, real money recognized in tariff".
- For the share of the ATEM already managed by the concessionaire, tariffs will be calculated on the basis of the previous RAB (CAPEX remuneration continues as before).

In both of these cases, at the end of the 12-year ATEM concession the DSO will have the right to cash-in the VIR (inflated and depreciated) plus the CAPEX made in the concession period (inflated and depreciated).

For the coming regulatory period, the tariff calculation model is expected to switch to a new mechanism based on **standard prices and an output-based model** in order to increase the "cost-benefit" balance for the customer (new consultation document – DCO 456/2016).

The original tendering schedule has been delayed, but most municipalities are expected to publish the tenders during the next three years (2017–2019). As of today:

- Less than 15 calls for tender have been published, a stark difference from the 74 originally planned
- The first tender – ATEM Milano 1 - ended the preparation phase with two participants, a2a (the outgoing concessionaire) and 2i rete gas

In this scenario, DSOs will have to manage multiple bids at the same time; larger operators will thus have a competitive advantage in terms of financial and technical capabilities.

…will drive the consolidation process

In the coming years, more than 6,800 concessions will be aggregated into 175 ATEMs, which will go through a regulated tendering process. At the same time, the number of DSOs is expected to decrease from around 200 to 40 by the end of the process.

Several DSOs have already declared their willingness to find partners and announced and/or finalized joint-venture agreements with Italian or foreign investors: Erogasmet/Osaka Gas JV (Osaka fully subscribed €75 mln of Erogasmet's capital increase), Lario Reti (looking for a partner in the gas distribution and energy retail business), Agam Alessandria (looking for a financial partner), Cogeser (looking for a partner to participate in the Milano 4 tender), Ascopiave/AEB-Gelsia (MoU to merge business units), Salerno Energia Distribuzione (looking for a partner to participate in five ATEM tenders in Southern Italy), Amgas Bari (looking for a partner to participate in the Bari 1 tender).

Expected post-tenders competitive scenario

Source: Source: Arthur D. Little analysis

Industrial and financial partnerships represent a key factor in strengthening incumbents' own technical and financial competitiveness in an attempt to ward off potential rivals.

The ATEM tender process

Ministerial Decree 226/2011 defined a standard tender process in terms of procedure, awarding criteria and timeline.

However, before entering into the tender process, the DSO must have a clear view about the ATEMs it wants to compete in (or exit from) and how aggressive its offer will be. For this purpose, target ATEMs need to be identified and ranked on the basis of a list of selection criteria.

Some of the typical **selection criteria** used to rank ATEMs' attractiveness are:

- **ATEM market share:** the greater the Incumbents' share in an ATEM, the greater the financial barriers and the DSO's technical knowledge of the ATEM.
- **VIR–RAB**: the difference between VIR and RAB is subject to a discount in the economic offer; ATEMs in which the difference is large are less attractive because the economic offer is more expensive (especially for the incumbent).
- **Competition**: ATEMs in which competition is expected to be low are more attractive from an economic point of view.
- **Geographical contiguity**: economies of scale and efficiency are positively correlated with ATEM contiguity and combination with other businesses (e.g. electricity distribution and water).
- **Publication date**: technical and financial capabilities are limited, and some ATEMs could or could not be selected depending on the timing.
- **Profitability:** in terms of IRR, NPV, EBITDA margin, etc., some ATEMs can be more profitable than others due to a balanced mix of factors.

Most of these criteria are based on estimated data that will be finalized only when tenders are published. A successful strategy would, first of all, be a **"rolling-based" strategy** that could evolve according to new data and information.

Tender process

Source: Arthur D. Little analysis

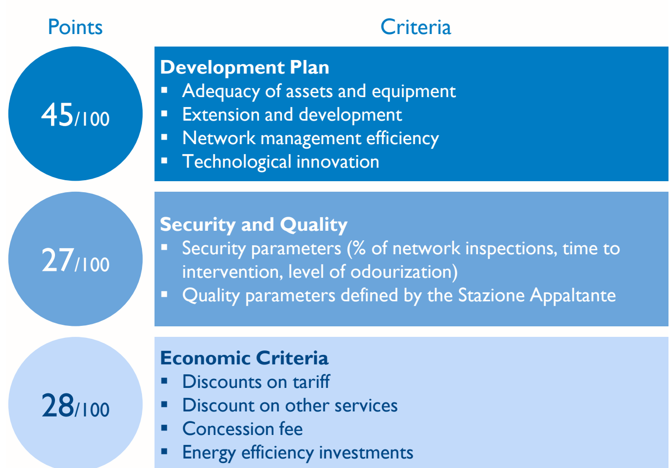
The **bid preparation** phase is expected to last six to eight months, though the deadlines of the first tenders already published have been postponed for several reasons.

In our experience, some key success factors for the offer preparation phase can be identified:

- Preliminary definition of team, role and responsibilities, as well as project management tools.
- Technical skills and good knowledge of an ATEM's peculiarities in order to develop a high-quality development plan.
- Clear understanding of the competition level to optimize the economic offer.

The **bid evaluation** is based on a standard scoring system mainly focused on technical criteria (development plan and level of quality and security).

Awarding system



The final step is represented by the **asset transfer** from the outgoing concessionaire to the new one. Disputes mainly related to the residual value of the assets and to the quality parameters of the awarding criteria may come from unsuccessful bidders.

After the transfer of the assets to the new concessionaire, a **post-merger integration process** has to be managed to minimize inefficiencies and to achieve economies of scale:

- Asset portfolio reorganization and data migration between the IT/accounting systems
- "New" personnel hiring and training process
- Process and organization reengineering

Opportunities for utility companies and infrastructure funds

In this scenario, several Italian DSOs could have the chance to exploit their assets by either exiting the business (at a value between RAB and VIR) or looking for an industrial/financial partner to participate in target ATEM tenders.

Investors can leverage this tender-season opportunity to enter the Italian gas distribution sector, which is characterized by the following main elements:

- Clear and stable regulatory framework
- Ongoing consolidation process with an opportunity to achieve significant economies of scale
- Huge CAPEX plan to be developed for each ATEM (smart meters and grid renewal)
- Predictable cash flow during ATEM concession and final value after 12 years
- Dividend flows expected to start later in the concession period due to CAPEX plan

Arthur D. Little has worked with several gas distribution companies, helping them with strategic, regulatory, operational and technical topics, as well as M&A transactions (buy side and sell side).

Thanks to our experience, ADL is the right partner to help investors in addressing this opportunity by assisting in the following main areas:

- Market analysis and scouting
- Regulatory analysis
- Business due diligence
- Technical due diligence (including VIR assessment)
- Business plan and valuation
- Transaction support

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