Report on international experiences with E1st

Project Acronym	Enefirst
Project Name	Enefirst – Making the Energy Efficiency First principle operational
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Project Duration	September 2019 – February 2022
Website	http://enefirst.eu

Deliverable No.	D2.2 - Report on international experiences with E1st
Dissemination Level	Public
Work Package	WP2 - Framework for operationalising E1st
Lead beneficiary	RAP
Contributing beneficiary(ies)	BPIE, CEU, Fraunhofer ISI, IEECP
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Reviewed by	Jan Rosenow
Date	June 2020
File Name	D2-2 Report on international experiences with E1st

To quote this reference, please use:

This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement No 839509.

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FOREWORD

ENEFIRST is a three-year project funded under the Horizon2020 programme, which gathers a consortium of partners from across sectors and regions: IEECP, BPIE, Fraunhofer ISI, CEU, RAP, IREES, TU Wien.

From definition to implementation, ENEFIRST aims to make the "Efficiency First" (E1st) principle more concrete and operational, to improve the understanding of its relevance for decision processes related to energy demand and supply and its broader impacts across sectors and markets, focusing on the building sector and related energy systems in EU Member States.

E1st gives priority to demand-side resources whenever they are more cost-effective from a societal perspective than investments in energy infrastructure for meeting policy objectives. It is a decision principle that is applied systematically at any level to energy-related investment planning and is enabled by an "equal opportunity" policy design.

ENEFIRST combines policy analysis and quantitative assessments of E1st impacts to develop policy guidelines and recommendations, following a process of continuous exchanges with stakeholders.

A previous report (ENEFIRST, 2020) discussed what is E1st, its background, and ways that it can be made operational in the various policy fields of the EU with relation to buildings.

This report complements these first analyses with practical examples of how the concept has actually been implemented – knowingly or tacitly – in various U.S. states and EU Member States.

This review of examples is primarily focused on buildings and related energy systems, in line with the scope of ENEFIRST.

The first part introduces the methodology used and provides an overview of the examples. The following parts discuss each example.

The examples can also be viewed separately on the website:

https://enefirst.eu/examples/

0 OVERVIEW OF THE EXAMPLES

0.1 Objectives and methodology used to review international experiences with E1st

This report reviews examples of policies, regulatory frameworks, utility programmes or other initiatives that have implemented the Efficiency First (E1st) principle[1] in practice. Its objective is to analyse **why and how E1st has been implemented**, and **what lessons can be learned** from these experiences. These examples also **show** policymakers, regulators and energy policy actors in general that the concept of E1st can be implemented and can provide various benefits to the energy transition.

Each example has been analysed according to the following issues:

- **Background**: rationale and main reasons why the initiative was launched/adopted, who is involved, how it works, the current status.
- **How the E1st principle (or similar concept) has been implemented**: how is the approach used in line with the E1st principle, the driver behind the choice of approach (e.g., legislation, energy regulation, specific objectives), and the role of the implementing bodies and stakeholders involved in the implementation of the initiative.
- **Effects and impacts**: information about the effects and impacts, and how these are monitored or evaluated.
- **Changes over time**: brief history of the changes in the features and implementation of the initiative.
- **Barriers and success factors**: barriers that had to be overcome (or that are still impeding the implementation of E1st) and the success factors that made it possible to overcome them, to involve stakeholders, etc.
- **Replicability and scalability**: potential of the approach to be replicated elsewhere or to be scaled up.

The sources used are listed at the end of each example.

The examples have been identified through literature review, personal communication, and web search. We did not aim for an exhaustive review.[2] Our objective was to cover a **diversity of situations and approaches**, in terms of types of policy, framework or initiative, types of energy carrier targeted, etc.

Our other objective was to include examples that clearly demonstrate **the implementation of an approach in line with E1st** — even if the use of the E1st concept is not explicit. Indeed, the official definition of E1st was only adopted in late 2018 in the Governance Regulation of the Energy Union (EU, 2018/1999,

[1] E1st gives priority to demand-side resources whenever they are more cost-effective from a societal perspective than investments in energy infrastructure in meeting policy objectives. It is a decision principle that is applied systematically at any level to energy-related investment planning and enabled by an "equal opportunity" policy design. For more details, see (ENEFIRST, 2020).

[2] Indeed, the concept of E1st is still recent and rarely explicitly mentioned in the official descriptions of policies or regulatory frameworks. Moreover, approaches in line with the E1st principle can be related to similar concepts, such as Integrated Resource Planning (for more details, see ENEFIRST, 2020). An exhaustive review can, therefore, not be done with a search based on keywords. It would require the screening of all of the policies within a given area and policy field to identify what policies include an approach in line with E1st. This was not possible within this project.

Art.2(18)). Therefore, the term itself is not yet widely used by policymakers and stakeholders, although approaches in line with the E1st principle have sometimes been implemented for many years.

A final objective was to select **new examples**, i.e., not already available in the literature, especially in (Rosenow et al., 2016). Examples available in the literature could be selected if a significant update seemed interesting to make. Table 9 in Part 17 of the report provides a list of other examples that can be found in the literature, together with the corresponding source (including the list of examples presented in (Rosenow et al., 2016)).

The selected examples can be categorised in various ways, such as according to the level and/or actor of decision/rule making, the energy carrier (electricity, gas, heat) concerned, or the EU policy affected. When trying to identify a **typology** that captures the implementation of the E1st principle most closely and offers comprehensive, yet not overlapping categories, we singled out two dimensions:

- Which section of the energy system is driving the measure:
    - **in-front-of-the-meter** infrastructure development and usage (such as generation, transmission and distribution power and gas networks, district heating networks, utility scale storage);
    - **or behind-the-meter** infrastructure development and usage (e.g., all investment linked to the building such as space and water heating, electrical appliances, lighting, PV, micro-storage, automation/AMI allowing demand response, etc.).
- Whether the provisions behind the equal treatment of demand and supply options:
    - focus on the use of these demand-side resources in energy system and market operation **in general**;
    - or are specifically linked to **investment decisions**.

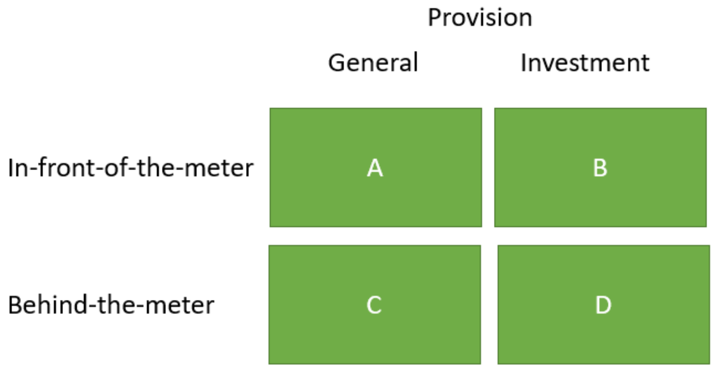


Figure 1 – Main categories of provisions to implement E1st

In the typology used for this report, "in-front-of-the-meter" means that the E1st provision applies to energy companies or other stakeholders involved in energy markets. "Behind-the-meter" means that the E1st provision first applies to energy end-users or building owners.

Likewise, "general" means that the E1st provision mainly deals with general frameworks (e.g., energy market regulations). "Investment" means that the E1st provision mainly deals with rules or incentives for investment decisions.

The **requirement level of the provisions or rationale** to implement E1st varies considerably, from voluntary initiative (e.g. pilot projects), to conditioning supply infrastructure investment on the execution of a priori demand reduction. We capture this dimension in the following labels that are attached to each example to show how soft/hard the implementation approach is:

1. **Allowing E1st**: allowing experiments or voluntary schemes promoting alternatives to investments in energy infrastructures
2. **Enabling E1st**: ensuring a level playing field between supply- and demand-side resources by removing the barriers to use and/or by revising the rules, criteria or conditions that make demand-side resources disregarded
3. **Requiring E1st-proof assessments**: Requiring the consideration/analysis of demand-side resources as alternatives to investments in energy infrastructures
4. **Evidence-based approval**: Approving only the investment or option that get the best rank in a substantiated cost-benefit analysis (e.g., based on cost-effectiveness or multi-criteria analysis), regardless of whether it is a behind-the-meter or in-front-of-the meter asset
5. **Encouraging E1st**: Providing incentives in favour of demand-side resources (recognising its hard-to-quantify benefits)
6. **Requiring E1st**: Requiring a minimum EE level/investment prior to investments in energy systems

Figure 2 – Requirement levels to implement E1st

In ENEFIRST, we use the following definitions about “demand-side resources” and “energy infrastructures”:

- **Demand-side resources** refer to technologies and actions that reduce the quantity and/or temporal pattern of energy for the same energy service. It includes end-use efficiency (often denoted as energy efficiency of both equipment and buildings) and demand response (often referred to as flexibility), which could include the use of storage. It, however, excludes distributed generation, which is included in the concept of DER (distributed energy resource) used in the U.S.
- **Energy infrastructure** refers to assets used for energy generation, transmission and distribution and utility-scale storage facilities. In ENEFIRST, we mostly deal with the energy infrastructures related to electricity, natural gas and heat/district heating.

0.2 Overview of the examples

This report includes the following 16 examples:

Table 1 – List of examples about implementing E1st

No.	Case	Type of provisions	Level of requirement	Region / Country	Targeted energy carrier(s)
1.	Using ToU (Time-of-Use) tariffs to engage consumers and benefit the power system	A. In front/ General	1. Allowing E1st	EU	Electricity
2.	Social Constraint Management Zones to harvest demand flexibility	A. In front/ General	1. Allowing E1st	UK	Electricity
3.	Demand flexibility in District Heating networks	A. In front/ General	1. Allowing E1st	EU	Heat
4.	Participation of Demand Response (DR) in French wholesale electricity market	A. In front/ General	2. Enabling E1st	France	Electricity
5.	Enabling rules for Demand Response (DR) aggregators	A. In front/ General	2. Enabling E1st	EU	Electricity
6.	Decoupling utility sales and revenues	A. In front/ General	2. Enabling E1st	EU	Electricity/Gas
7.	Replacing a polluting power plant with behind-the-meter resources	B. In front/ Investment	2. Enabling E1st	U.S. (California)	Electricity
8.	Updating distribution system planning rules in Colorado and Nevada	B. In front/ Investment	3. Requiring E1st-proof assessments	U.S.	Electricity
9.	Assessing the value of demand-side resources	B. In front/ Investment	3. Requiring E1st-proof assessments	U.S. (New York)	Electricity
10.	Water heaters as multiple grid resources	C. Behind / General	1. Allowing E1st	U.S. (Hawaii)	Electricity
11.	Building Logbook – Woningpas: Exploiting efficiency potentials in buildings through a digital building file	C. Behind / General	3. Requiring E1st-proof assessments	Belgium (Flanders)	All
12.	Optimising building energy demand by passive-level building code	C. Behind / General	6. Requiring E1st	Belgium (Brussels Capital)	All
13.	Deferring T&D (Transmission & Distribution) infrastructure investments through local end-use efficiency measures	D. Behind/ Investment	1. Allowing E1st	U.S. (California)	Electricity
14.	Building energy performance requirements of the Irish Heat Pump System grant	D. Behind/ Investment	6. Requiring E1st	Ireland	All
15.	Fabric First approach under the Better Energy Communities grant scheme	D. Behind/ Investment	6. Requiring E1st	Ireland	All
16.	Linking RES (Renewable Energy Sources) support to building energy performance	D. Behind/ Investment	6. Requiring E1st	UK	All

Half of the examples analysed deal specifically with the **electricity system**. This predominance in this sample can be explained by the fact that **interactions between supply and demand** are critical for electricity systems at all times. Therefore, options such as demand-response or time-of-use tariffs have mostly been developed for electricity. This can also be seen, for example, in the history of Integrated Resource Planning that has been mostly focused on planning for the needs of electricity systems (see section 2.1.3 in ENEFIRST, 2020). The supply of the other energy carriers can be more easily controlled and adapted to the demand.

Most of the examples not dealing specifically with electricity can be considered as dealing with **all energy carriers**. These interventions either deal with all energy end-uses in buildings or are focused on heating without focusing on a particular energy carrier. These interventions are indeed sometimes allowing, or even encouraging, **energy switching**. More generally, **reducing the energy consumption** is most often one of the main objectives of the initiatives described in these examples.

Only a few examples specifically address **natural gas and district heating** because these types of cases were more difficult to identify. The same can be observed in the list of examples found in other sources (see Table 9 in part 17). This might suggest that guidelines would particularly be useful to develop the E1st approach in relation to natural gas and district heating.

The benefits of an improved flexibility in the demand are more obvious for electricity systems. However, all energy systems can benefit from an improved demand-side management. Moreover, demand response is only one of the demand-side resources. The implementation of the E1st principle deals with other demand-side resources, and especially with end-use energy efficiency aiming at a reduction of energy consumption. Any energy efficiency programme could thus be considered as contributing to the implementation of E1st. Moreover, there are options that involve both demand response and end-use energy reduction: high energy performance buildings act as storages and allow for a more power system aligned operation of electric heat pumps. However, in this report, we focus on examples where energy efficiency is explicitly promoted **taking into account the interactions with energy systems** that supply the energy to meet the targeted energy need(s) or end-use(s).

The categories shown in Figure 1 can also be related to the main decision frameworks where it is highly relevant to integrate the E1st principle in the decision processes. Table 2 shows how the examples fit to these frameworks.

Table 2 – Examples by the decision frameworks

Type of provision	Type of decision framework	Example(s)
A – In front / General	Energy market regulations	(1-ToU tariffs), (4-NEBEF in France), (5-Aggregators)
	Network regulations	(6-Decoupling sales and revenues)
B – In front / Investment	Regulatory frameworks for investment planning for energy infrastructure	(7-replacing a power plant), (8-planning rules in Colorado and Nevada), (9-value of demand-side resources)
C – Behind / General	Regulatory frameworks related to energy in buildings	(11-building logbook), (12-Passive level building codes)
	Utility programmes or action plans	(2-SCMZ), (3-demand flexibility in district heating), (10-water heaters), (13-geotargeting of EE programmes)
D – Behind / Investment	Rules for the use of EU-related funds or carbon revenues	
	Incentive schemes for investments in buildings and on-site energy systems.	(14-Heat Pumps scheme), (15-Fabric First Approach), (16–RES and EPC)

For more details about the links between implementing E1st and decision frameworks, see ENEFIRST, 2020.

0.3 Short summaries of the examples

1 Using Time-of-Use tariffs to engage customers and benefit the power system: Demand response is key for a renewable-powered future, paving the way for an ongoing integration of variable renewable energies as well as for limiting investments in grid reinforcements and in peak capacity. Time-of-use (ToU) tariffs are an important enabler of demand response by incentivising customers to shift their electricity use from high- to low-demand periods, allowing them to save on energy expenses while benefitting the power system.

2 Social Constraint Management Zones to harvest demand flexibility: Instead of accommodating increasing electricity demand by extending the capacity of the network, the new Social Constraint Management Zones (SCMZ) initiative of Scottish and Southern Electricity Networks (SSEN) involves the procurement of “smart” or “non-wires” solutions from residential and community consumers in congested areas in its network.

3 Demand flexibility in District Heating networks: The aim is to improve the load factor of the households regarding heating. This has the potential to improve the attractiveness of district heating (DH) and accelerate the rollout of DH networks. Capital costs are lowered by reducing required boiler capacity and pipework sizes. Operational costs are reduced by increasing the coverage of the primary plant and reducing heat losses and pumping energy. Shaping heat load and the reduction of demand peaks have the potential to improve network efficiency, integrate renewable energy sources, and reduce capital costs within the network. Experimental studies on thermal peak shaving in district heating networks resulted in peak reductions between 5% and 35%, depending on the limitations of the modifications.

4 Participation of Demand Response in French wholesale electricity market: In France, the NEBEF mechanism opens the participation of demand response in wholesale electricity markets, mostly through aggregators. While the mechanism is innovative, it does not on its own sustain the aggregators’ business models.

5 Enabling rules for Demand Response aggregators: Many renewable electricity sources are intermittent. The integration of wind and solar power can be enabled by the activation of flexible demand. Germany is an example of a partly developed flexibility market. The case points out recent improvements as well as barriers. In addition, further regulatory issues are described.

6 Decoupling utility sales and revenues: Utilities are responsible for providing customers with reliable and reasonably priced energy services. However, under traditional regulation, utilities – such as electricity and gas network operators – are discouraged from investing in cost-effective energy efficiency because it lowers their revenues. An established way to remove this conflict is to break the link between the utility's revenue and the amount of energy it sells or transmits in order to ensure that the utility recovers its capital expenditures and operating expenses plus an authorised return on investment, no less and no more. In combination with other regulatory mechanisms, such decoupling mechanisms can induce utilities to help customers save energy whenever it is cheaper than producing and delivering it.

7 Replacing a polluting power plant with behind-the-meter resources: In Oakland, California, the utility PG&E and the community electricity supplier EBCE have organised a bid to replace an old and polluting peak fossil fuel plant with clean resources. This iconic project demonstrates how demand-side resources can participate in reliability and adequacy objectives while bringing immediate clean air benefits to local communities.

8 Updating distribution system planning rules in Colorado and Nevada: The growth of distributed energy resources and their important benefits for the power system requires proper planning at the distribution system level. In the U.S., several states, including Colorado and Nevada, have recently adopted distribution planning rules.

9 Assessing the value of demand-side resources: U.S. utilities are required to develop appropriate methodologies for evaluating non-wire solutions (NWSs), which are essential for the integration of NWSs to address pressing grid problems. ConEd's BCA (Benefit-Cost Analysis) Handbook includes many critical elements required for the assessment of demand-side resources.

10 Water heaters as multiple grid resources: Tanks equipped with electric resistance water heaters are widely used domestic appliances in some countries like U.S. or France. Traditionally, they are used as thermal storage devices by delinking the time of demand for and the generation of hot water: heating up water in the tank in periods of low overall power demand (e.g., at night). However, with a minor upgrade, these appliances can provide further grid services as well as save money for consumers. A recent programme in Hawaii is a prime example of stacking various system benefits from water heaters, and showcases how a third-party service provider start-up can come up with solutions for efficient grid operation.

11 Building Logbook – Woningpas: Exploiting efficiency potentials in buildings through a digital building file: A (digital) building logbook is typically described as a digital repository where all of the information related to the building (including ownership, building design, materials used, structures, installations, systems, adaptations, investment, operational and maintenance costs, health and safety, performance indicators, certifications) are compiled and later updated when changes occur. Compiling and streamlining the use of data and making it accessible to the public in an anonymised way could influence the effectiveness of policies, simplify administrative procedures, and contribute to a stronger link between the building's energy performance and its value. Logbooks have been recognised – and developed in some countries — as a way to inform and engage building owners and possibly even decision-makers and maximise the value of energy performance certificate (EPC) data during a renovation.

12 Optimising building energy demand by passive-level building code: Passive level building codes were introduced in the Brussels Capital Region for new construction in 2015 and extended to a variety of renovations; this is expected to lead to a transformation of the whole building stock by 2050. Constructing buildings with an energy performance of close-to-passive level is only possible with a design in which energy demand is drastically reduced and the rest is supplied with renewables (RES); in this way, the efficiency first principle is naturally committed to. Brussels has been exemplary in developing the market solutions before introducing a regulation, and thus achieving a very low or no cost premium on passive design.

13 Deferring T&D (Transmission & Distribution) infrastructure investments through local end-use efficiency measures: Transmission and distribution system operators are subject to ongoing investment needs for their capital assets. In the U.S., several electricity and natural gas utilities have made successful use of locally targeted energy efficiency programmes to defer some of these investments in specific areas for a period of time. These projects highlight how the trade-off between demand-side resources and energy infrastructure can be practically solved, with benefits accruing to both the utility and its customers. This example discusses such activities of the California utility Pacific Gas and Electric (PG&E). Similar activities are underway or have been pursued in the states of New York, Vermont and Oregon.

14 Building energy performance requirements of the Irish Heat Pump System grant: The eligibility criteria of the Heat Pump System grant implemented by SEAI (Sustainable Energy Authority of Ireland) requires a minimum level of building energy performance and is a good example of the E1st principle applied in building policy. The requirement of a certain energy performance level prior to supply-side investments ensures, in this case, that the heat pump system works efficiently, and that the subsidy is allocated effectively. The grant incentivises renewable heating systems while prioritising energy efficiency, which is essential to achieve a decarbonised building stock.

15 Fabric First approach under the Better Energy Communities grant scheme in Ireland: The Better Energy Communities is a renovation grant scheme administered by SEAI (Sustainable Energy Authority of Ireland) which applies an energy efficiency first approach. The scheme funds local residential and non-domestic energy projects which prioritise energy efficiency measures over renewable and smart technologies. Requirements include an energy performance level corresponding to a Building Energy Rating (BER) of B2 to be achieved after the renovation works. These performance-based requirements are communicated as Fabric First approach: they imply to improve first the performance of the building envelope before replacements of heating systems can be eligible to grants.

16 Linking renewable support to building energy performance: Optimising distributed renewable investment along with energy efficiency seems to be a common sense approach: it makes sense to size on-building renewable (or other) generation capacity to a demand level that has already been reduced to a cost-efficient minimum. Conditioning public support for distributed energy supply on a predefined minimum level of building energy performance is an implementation of the E1st principle with a large scalability potential. This case is about linking the feed-in tariff in the UK to minimum building standard.

0.4 Lessons learned and next steps

The collection of E1st applications presented in this report is by no means a comprehensive mapping of such applications. They have also not necessarily been implemented as explicit applications of the E1st principle; rather, they are often considered simply as a smart use of available resources.

There may be **various motivations** behind developing an E1st (or similar) approach, such as the political will to reduce the need for new networks and energy infrastructures, mobilisation of consumers in emergency situations, reducing power system balancing costs, or taking into account the need to reach higher levels of energy efficiency and energy savings to make it possible to achieve long-term energy and climate goals. Demand-side resources (including both, end-use energy efficiency and demand response) as an alternative to supply-side investments have been more often used in the U.S., especially in the power system and markets,[3] where the integration of demand-side resources began in the 1980s and is embedded in the wider scope and mandate of energy sector planning (ENEFIRST, 2020).

The benefits from implementing E1st can occur at **various scales and time horizons**. From short-term flexibility in the energy demand (e.g. with Time-of-Use tariffs as in example 1; or demand response as in examples 4 and 5) to long term reductions in GHG emissions by avoiding lock-in effects for energy savings in buildings (see examples 11, 12, 14, 15 and 16). From limiting the needs in on-site heat generation (see examples 14 and 15 about the Fabric first approach developed in Ireland) to avoiding a power plant (see example 7).

Two of the examples use a **geographically-targeted approach** (see examples 2 and 13). Example 8 related to distribution system planning in Colorado and Nevada points out the pros and cons of area-based planning or programmes: targeted schemes enable to enter more into the details of the interactions between supply and demand, and to focus the interventions where the most effective or needed. While schemes with broader scopes enable a better coordination among system operators. The area taken into account in the scheme depends on the type of energy systems considered (e.g. area supplied with district heating, see example 3), and the targeted segment(s) of the energy system (generation, transmission, distribution).

Many of the examples we found are **recent** (i.e., began within the last two or three years). This is partly because older examples of E1st implementation was collected in previous studies (particularly in Rosenow et al., 2016). Information about the impacts of these recent interventions is limited. As in some cases, they are still in an experimental stage or offer just one or two years of full-scale implementation for review. However, they can already provide a feedback about the motivations to develop an E1st approach, and how this approach has been developed.

Interestingly, this dynamic of recent initiatives is not necessarily driven by new regulations or requirements. Energy companies or energy agencies have sometimes developed innovative programmes of their own initiative (see examples 4, 7, 13, 14, 15). These **voluntary initiatives** are usually related to energy and climate objectives. They can also have multiple purposes, such as local jobs (see example 15) or avoiding environmental impacts generated by new energy infrastructures (see example 7).

New approaches (e.g., demand response) can sometimes be hindered by regulatory frameworks that might have been first designed to organise the supply-side of energy. Several of the examples show how regulatory frameworks can be adapted to **enable the development** of approaches relying on demand-side resources (see examples 1, 4, 5, 6), or to give them the priority. The recast or amendment of the European directives included in the Clean Energy for All Europeans package should also serve as a baseline and a window of opportunity at the same time to form aligned national regulations, based on these good practices.

The examples show that **regulations or mandatory requirements** can be effective in **wider, or even systematic, adoption** of the E1st principle in assessments made by utilities (see examples 8 and 9) or in investments made by building owners (see examples 14, 15 and 16). However, the latter examples also

[3] At least more literature can be found about Integrated Resource Planning or other approaches close to the E1st principle for the electricity systems in the U.S.

pointed that higher requirements might lead to a lower number of building renovations supported, at least in a first time after adopting these higher requirements (see experience from example 15). **Complementary support** is thus needed to reach both a high energy efficiency ambition and a high number of projects. This might imply additional financing aids, but also accompanying market actors to appropriate the E1st approach and develop offers that can meet the requirements. For example, training or other supporting schemes can be useful to make installers from different building trades work together and develop offers for comprehensive renovation. Implementing E1st therefore goes beyond adapting the frameworks for investment decisions. It requires to have a broader view of the possible solutions to meet the energy needs, to break the silos and favour more interactions and coordination among actors of the supply-side and demand-side.

Two forthcoming reports in the ENEFIRST project will analyse the examples further and bring complementary inputs to the background analysis about how E1st implementation can be developed:

- The first one will focus on the **barriers of implementation** identified in the cases and in a survey of stakeholders in spring 2020.
- The second one will discuss the **applicability** of implementing E1st in Europe: what provisions in the European legislation can support (or hinder) the implementation of the E1st principle, where these provisions are obviously missing (legal/policy screening), and what the transferability conditions are (market, social, behavioural, etc.).

1 USING TIME-OF-USE TARIFFS TO ENGAGE CUSTOMERS AND BENEFIT THE POWER SYSTEM

Country/region	Europe
Type of E1st approach	A – In front / General 1 – Allowing E1st (Energy market regulation)
Energy carrier(s) targeted	Electricity
Sector(s) / energy system(s) or end uses targeted	Residential
Implementing bodies	Regulatory authorities
Decision-makers involved	Suppliers, consumers
Main objective(s)	System integration of renewable energy sources, lower energy bills, reduced supply-side infrastructure
Implementation period	1960s – ongoing

Demand response is key for a renewable-powered future, paving the way for an ongoing integration of variable renewable energies as well as for limiting investments in grid reinforcements and in peak capacity. Time-of-Use (ToU) tariffs are an important enabler of demand response by incentivising customers to shift their electricity use from high- to low-demand periods, allowing them to save on energy expenses while benefitting the power system.

1.1 Background

Demand response is a key flexibility resource in power systems with increasing shares of variable renewable energy (VRE) generation. An important element of demand response is ToU tariffs that incentivise customers to adjust their electricity use voluntarily – either through automation or manually – to reduce their expenses. As the name suggests, the price signals are time-varying, reflecting the marginal network costs and/or generation costs of energy in the wholesale market.[4] The price signal can be static or dynamic, or a combination of the two (ACER/CEER, 2016; IRENA, 2019), as illustrated in Figure 3.

[4] Demand response programmes based on ToU tariffs are also referred to as *implicit demand response*. In turn, trading committed and dispatchable flexibility in power markets (single consumers or through "aggregators") is referred to as *explicit demand response* (SEDC 2016).

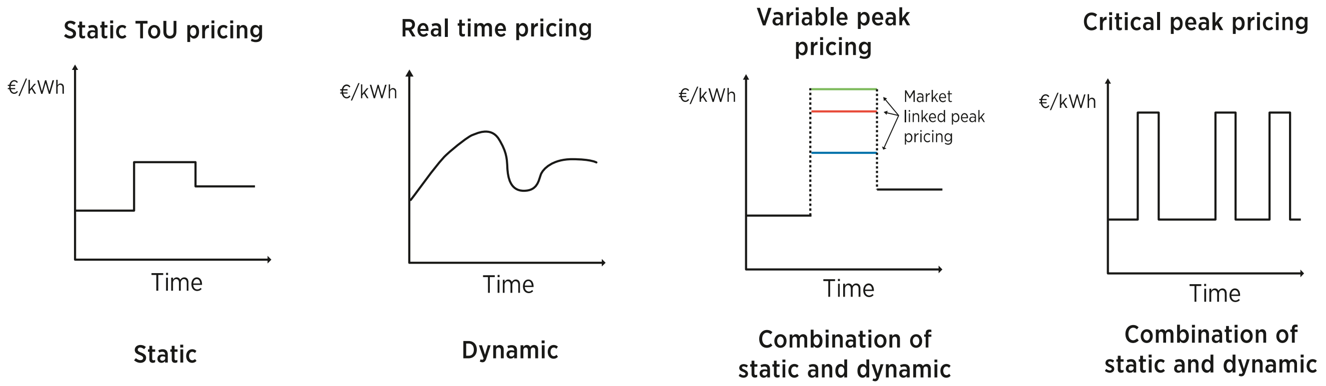


Figure 3 – Forms of Time-of-Use signals

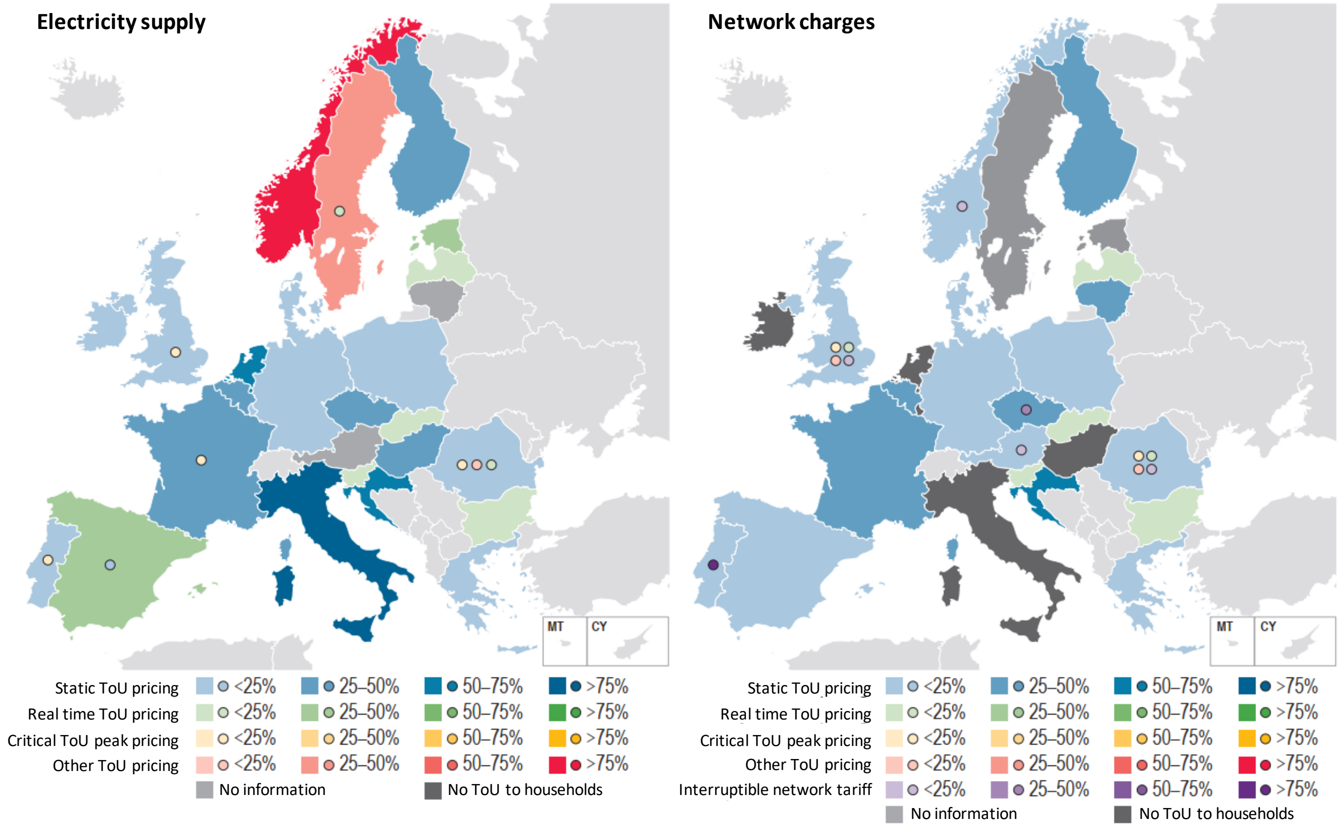
(Source: IRENA 2019)

A *static signal* is determined in advance, typically applied to usage over time blocks of several hours for which the price remains constant. This can be simple day- and night-pricing to reflect on-peak and off-peak hours. *Dynamic signals* are determined in "real-time," based on actual system conditions. Prices in a dynamic setting are calculated based on at least hourly metering of electricity use, or within even higher granularity (e.g., 15 minutes). Combinations of static and dynamic signals include *variable peak pricing* (different periods for pricing defined in advance, but price for on-peak period varies by market conditions), and *critical peak pricing* (e.g., the French Tempo tariff[5] in which electricity prices increase substantially only a few days in a year).

1.2 How has the E1st principle (or similar concept) been implemented?

Providing ToU tariffs to customers requires advanced metering devices to track the consumption of individual consumers. If investments in such cost-effective ToU equipment, as well as setting up and operating the overall demand response programmes, is preferred over investments in reserve capacities, network upgrades and other supply-side infrastructure, the Efficiency First principle is met. In terms of actual implementation, many EU Member States (MS) already have wide experience with the different forms of ToU tariffs. Figure 4 illustrates the share of households per country that are supplied under different ToU pricing for electricity and network charges, as of 2015.

[5] https://particulier.edf.fr/en/home/energy-and-services/electricity/tarif-bleu.html



Note: Countries are coloured according to the ToU method that is the most representative. The coloured dots represent additional ToU pricing methods which also appear in a country.

Figure 4 – Share of household consumers supplied under Time-of-Use pricing for electricity supply and network charges in European countries

(Source: ACER/CEER 2016)

It is apparent that ToU tariffs are typically applied in the supply of energy rather than in network charges. The most commonly applied type of ToU for electricity supply is static pricing with a day/night differentiation, which has a particularly large share in Italy. Hourly real-time pricing is used predominantly in six European countries: Estonia, Latvia, Spain, Slovakia, Slovenia and Bulgaria. Critical peak pricing is used to a minor extent in different countries, such as in France where the "Tempo" tariff has been chosen by 1.2% of households (Rosenow et al., 2016). Other dynamic pricing methods apply to a large electricity household base in two countries, Norway and Sweden. There, electricity consumers typically incur spot-market-based pricing through the monthly average wholesale price. For example, in Denmark consumers pay for electricity upfront on a monthly basis and face subsequent corrections to reflect the real price paid by suppliers on the spot market as opposed to the forecast price. Similar to electricity tariffs, static pricing is the most common type of ToU pricing for electricity networks, applied in 15 out of 22 countries for which information is available. Overall, electricity tariffs are changing rapidly across Europe with, for example, tariffs favouring residential on-site PV (photovoltaic) for self-consumption becoming more widespread and adding complexity to the system (ACER/CEER, 2016; IRENA, 2019).

1.3 Effects / impacts

ToU tariffs facilitate demand response as, to varying degrees, they reflect marginal generation costs of energy and/or network costs. As such, consumers have an incentive to change their consumption in response to time-based price signals, which can benefit the whole power system (ACER/CEER, 2016). On one hand, demand response programmes based on ToU tariffs have the potential to become one of the most cost-effective flexibility resources in the power system, key to enabling the integration of high shares of variable renewable energy (VRE) generation from wind power and photovoltaics (IRENA, 2019). By shifting demand towards periods of abundant VRE generation and decreasing demand in times of high residual load, demand response can substantially reduce the curtailment of VRE resources and improve the system's reliability. On the other hand, the increasing responsiveness of customers to ToU tariffs enables system operators to save on investments in generation reserve capacities by shifting demand to off-peak or lower-price time intervals. Also, by reducing peak demand, investments in network upgrades can be deferred or reduced (IRENA, 2019).[6]

According to the American Council for an Energy-Efficient Economy (ACEEE), in the U.S. during 2015, about 200 TWh of electricity, or more than 5% of retail sales, were saved due to demand response programmes. This also substantially reduces peak demand. On a median basis, for each 1% reduction in electric sales for a utility, peak demand reductions from demand response programmes are 0.66% of peak demand for the utility. If these trends hold for future years, it would mean that for a utility that reduces retail sales by 15%, peak demand savings will be around 10% (ACEEE, 2017). For the EU, the aggregated theoretical demand response potential at present is estimated to at least a 61 GW for load reduction and to 68 GW for load increase, available in every hour of the year (Gils, 2014). With regard to consumer responsiveness to ToU tariffs, a pilot programme was conducted in Gotland, Sweden. During its initial stage, 23% of total electricity use occurred during the five most expensive hours of the day. In response to the newly integrated price signals, this dropped to 19% and 20% in the first and second year of the programme (World Economic Forum, 2017). The French Tempo tariff – a critical peak pricing tariff launched in the 1990s – has reduced national peak load by about 4%, with households shifting about 6 GW of load daily (Rosenow et al., 2016). Overall, by enabling demand response, ToU tariffs are key for efficient power system operation.

1.4 Changes over time, if any

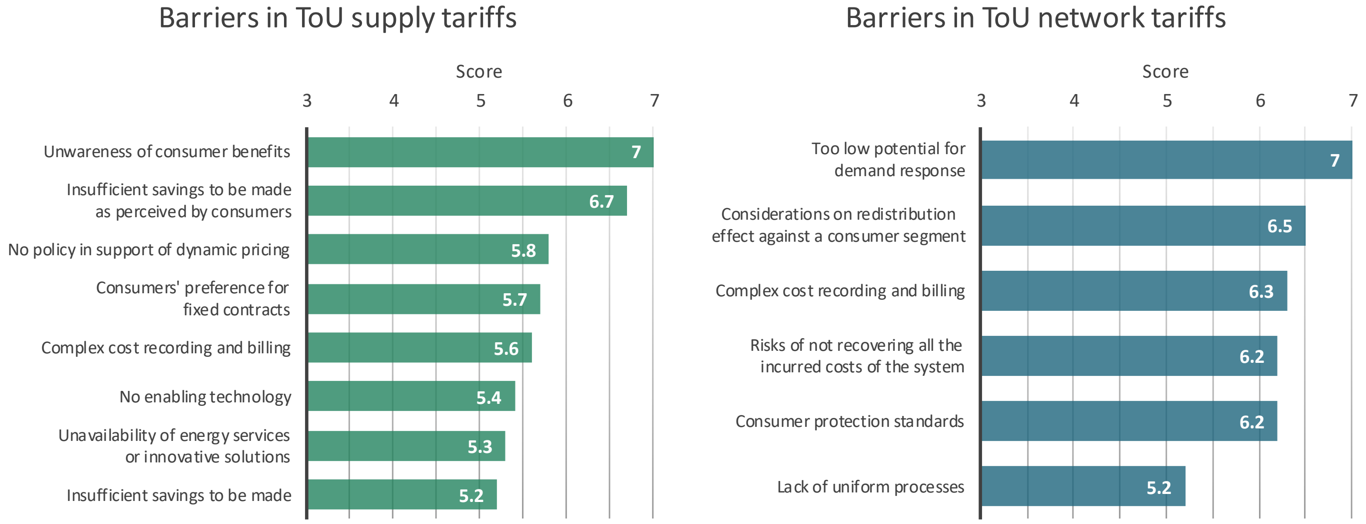
The implementation of ToU tariffs started in Europe in the 1960s when electrical heating became more popular. Static day/night ToU tariffs were used to shift the heating demand to the night when power demand was generally low and affordable. Over time, additional and more complex dynamic tariffs entered the market. The EU policy framework for the development of demand response and associated ToU tariffs in the EU has essentially been provided through the 3rd Internal Electricity Market Directive (2009/72/EC) as well as the Energy Efficiency Directive (2012/27/EU). These required enabling demand response to

[6] Note that network dynamics are different from supply dynamics, but they can interact, which makes it challenging to expose consumers to the correct cost-reflective price signals. Under specific conditions, wholesale market and network signals might even be contradictory, sending mixed messages to consumers to reduce their consumption based on the local distribution network congestion, but to increase consumption due to low supply prices. These coordination challenges are a matter of increasing practical experience and ongoing research (ACER/CEER, 2016).

participate in retail and wholesale markets according to its technical possibilities. As part of the recent 'Clean Energy for All Europeans' package (European Commission 2016), the recast Internal Electricity Market Directive ([EU] 2019/944) and Electricity Regulation ([EU] 2019/943) add provisions that improve the status of demand response. This includes the standing of demand response in capacity markets as well as the role of aggregators in bundling the flexibility of numerous customers (Pató et al., 2019). Yet, considerable barriers facing demand response and associated ToU tariffs persist.

1.5 Barriers and success factors

The adoption of ToU tariffs by consumers is subject to various barriers. Figure 5 provides a ranking of these barriers for electricity supply tariffs (left) and for network tariffs (right). These barriers were identified by National Regulatory Authorities (NRA), several of which have experience in the field with introducing ToU tariffs in their Member States (ACER/CEER, 2016). In electricity supply, a lack of awareness and consumer motivation are the key reasons why ToU pricing in electricity is not applied in many MS. To address this, consumer engagement can be encouraged through consumer information efforts and by designing easily usable dynamic pricing (IRENA, 2019).



Note: The respondents (NRAs) were asked to rank the barriers on a scale from 1 ('Existence of a barrier which is not at all important') to 10 ('Existence of a barrier which is very important'). The average of the rankings is presented per identified barrier.

Figure 5 – Underlying barriers to dynamic pricing in electricity supply and network tariffs to household consumers in a selection of EU Member States

(Source: ACER/CEER, 2016)

However, consumers' monetary savings might still be limited because of weak price signals. These can be explained by the structure of electricity bills. Typically, only one third of the bill consists of the actual energy price; the remaining two thirds represent network costs, taxes and levies. By reducing the tariff components, policy frameworks could significantly support the uptake of ToU tariffs (EURELECTRIC, 2017). Another important barrier to dynamic ToU pricing is the limited availability and the associated costs of enabling technologies. This includes smart meters, controlling devices for household appliances and electricity price communicators, which provide accurate information and allow customers to shift loads without having to follow price signals and manually operate electrical appliances. Given the high initial costs for such automation devices, financial models that combine ToU tariffs with smart home utility leasing could be beneficial for an increasing interest in ToU tariffs (EURELECTRIC 2017; IRENA 2019; ACER/CEER 2016).[7]

1.6 Replicability and scalability potential

Demand response programmes using ToU tariffs can be implemented for various consumer types (residential, tertiary, industry), if hardware, software and market requirements are met. Most important is an advanced metering infrastructure for two-way communication between supplier and consumer. Scaling effects significantly depend on the success of consumer recruitment and the consumers' engagement (IRENA, 2019).

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[7] According to a British survey (Fell et al., 2015), 25% of respondents somewhat or strongly agree to sign up if they were offered a dynamic ToU tariff. This share increases to 29% for dynamic ToU tariffs if a high degree of automation is included. The arrangement most preferred by respondents is direct load control (37% somewhat or strongly agreeing to sign up if offered).

Pató, Z.; Cowart, R.; Rosenow, J. (2019). Efficiency first in Europe's new electricity market design – how are we doing? Proceedings of the ECEEE 2019 Summer Study, 495–502.

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2 SOCIAL CONSTRAINT MANAGEMENT ZONES TO HARVEST DEMAND FLEXIBILITY

Country/region	UK (Scotland and South of England)
Type of E1st approach	A – In front / General 1 – Allowing E1st (Utility programmes or action plans)
Energy carrier(s) targeted	Electricity
Sector(s) / energy system(s) or end uses targeted	Distribution
Implementing bodies	Scottish and Southern Electricity Networks (SSEN)
Decision-makers involved	Scottish and Southern Electricity Networks (SSEN) and final consumers
Main objective(s)	Reducing winter evening peaks to avoid the reinforcement of the distribution grid
Implementation period	Operational since 2018

Instead of accommodating increasing electricity demand by extending the capacity of the network, the new Social Constraint Management Zones (SCMZ) initiative of Scottish and Southern Electricity Networks (SSEN) involves the procurement of “smart” or “non-wires” solutions from residential and community consumers in congested areas in its network.

2.1 Background

SSEN is the owner of two electricity distribution networks (in Scotland and South of England) and one electricity transmission network (in Scotland). It serves 3.5 million customers across one third of the UK’s landmass.

On winter evenings when the load peaks, sections of the local electricity network approach their maximum capacity. SSEN has been looking to alternatives to upgrading the cables and substations by managing local demand, storage and generation in areas with capacity constraints, e.g., mitigating peak load on a neighbourhood substation or mitigating peak infeed into the grid by consuming or storing locally produced energy (SSEN, 2020). It initially designated three areas as Social Constraint Management Zones (SCMZ) in 2018, out of which two areas are already operational: consumers can offer their demand flexibility to the DNO (distribution network operator, as DSOs – distribution system operators are called in the UK) in tenders.

The SCMZ programme was funded through the Network Innovation Allowance, which is an element of the regulatory framework (called *Revenue=Incentives+Innovation+Outputs* or RIIO) defining the allowed revenue of network companies. The Network Innovation Allowance provides limited funding to network companies to use for smaller technical, commercial or operational projects directly related to the licensees network that have the potential to deliver financial benefits to the licensee and its customers.

2.2 How has the E1st principle (or similar concept) been implemented?

The objectives of the Social Constraint Management Zones (SCMZ) initiative of Scottish and Southern Electricity Networks are to provide a way for communities to get involved in the solution and to receive payments for either reducing their peak demand, shifting their electricity consumption in time, or reducing their overall demand permanently.

Consumers and a variety of other suppliers who can deliver solutions to grid congestion, ranging from battery storage to energy efficiency, have been invited to offer flexibility services to the DSO. Anything that reduces or shifts demand is suitable, such as LED lighting installation programmes or utilising variable rate electricity tariffs. Here are two more examples:

1. A housing association plans to improve the insulation in its building stock to achieve the required standard assessment procedure ratings. By committing to this investment and focusing on the SCMZ area, the housing association can gain additional contributions toward the costs.

2. A local government wants to promote energy efficiency measures in a given area. By identifying and promoting the kinds of steps customers may take, the local government can receive payments toward furthering the initiative based on performance and measurable energy performance improvements (Reid et al. 2018).

Table 3 – Solutions considered for the SCMZ project and their attractiveness to the DNO

	Measure Type			Contract Type			
	Energy Efficiency & Savings	Indirect Demand Response	Direct Demand Response	Utilisation	Availability	Traditional Mix	Attractiveness to Network Operator
Domestic LEDs	X				X		✓✓
LED Streetlighting	X				X		✓✓✓
Commercial / Office LEDs	X				X		✓✓✓
Domestic Solar PV	X				X		✓✓
Loft insulation	X				X		✓✓✓
Cavity wall insulation	X				X		✓✓✓
Solid wall insulation	X				X		✓✓✓
Automation of heating	X				X		✓✓

controls							
Replacing electric showers	X				X	X	✓
Heat pump replacing peak rate electric heaters	X	X			X		✓✓✓
Leaflets and reminders	X	X			X	X	✓
Smart Apps for behaviour change	X	X	X		X	X	✓
Large domestic battery on a time-of-use tariff		X		X			✓✓✓
EV charging: delaying charge time	X	X		X			✓✓✓
Solar Battery		X		X			✓✓✓

(Source: SSEN, 2020)

SSEN reviewed potential regions for the initiative and selected three zones in 2018 (shown in Figure 6) that have sufficient commercial value to proceed with a tender.

The two SCMZs that are operational are:[8]

- Drayton area, where there is a need for up to 5MW of flexibility during November from 16:30 to 18:10 on weekdays. There may be about six congestion events per year depending on network demand.
- Coxmoor Wood area, where there is a need for 3.5MW of flexibility between December and February from 15:50 to 20:20. Again, there may be about six congestion events per year.

Scottish and Southern Electricity Networks has teamed up with the fuel poverty charity National Energy Action (NEA) to mobilise communities and community organisation to provide the needed flexibility services. The process, depicted in Figure 7, entails multi-staged bidding preceded by partnering workshops where potential flexibility suppliers have been invited. Projects are expected to be operational by the end of March 2021.

[8] https://www.nea.org.uk/technical/scmz/

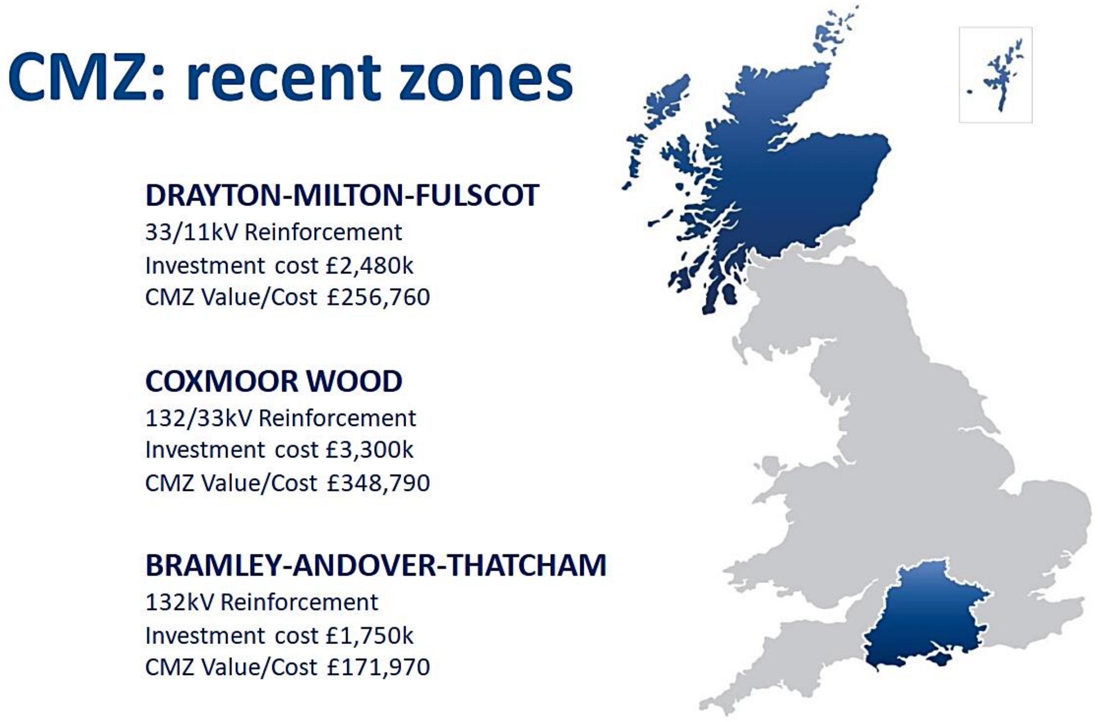

Figure 6 – Social Constraint Management Zones

(Source: Reid et al., 2018)

Consumers/communities with as little as 50kW in demand reduction can enter the auction; no demand response aggregator is required for participation. This allows the plan to include a broad range of participants. Flexibility revenue can be matched by other financial sources, such as ECO, Warm House Fund or the Domestic Renewable Heat Incentive, to improve the business case of the projects.

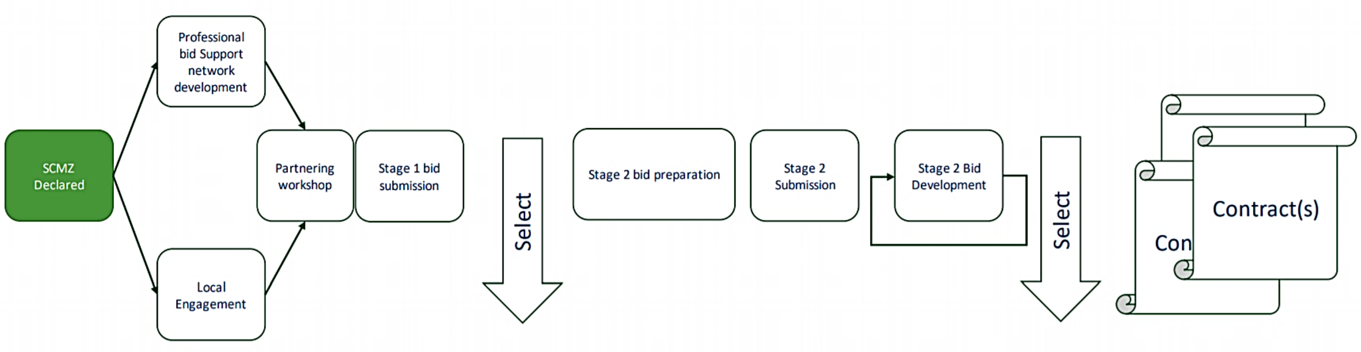

Figure 7 – The contracting process

(Source: Reid et al., 2018)

Potential EE/DR providers are provided seed funding and expert advice for those suitable proposals which pass a short prequalification questionnaire. Support is available to help them through the tender process as well.

Once the project is operational, SSEN will call upon the flexibility service when needed in various ways such as automatic dispatch, phone calls or email. One-day advance notice is expected on the potential service requirement. Validation of delivery is made through SSEN network monitoring. Payments are contingent upon validation and will be made as agreed by the contract.

The programme offers three different types of contract, usually for four years:

- Utilisation only: The provider is paid on a per-event basis when the flexibility is provided and used. It is best suited to behavioural signal projects.
- Traditional mix: Payments are made both during the specific network overload event (utilisation), and for the periods when flexibility is normally required. It is best suited to a traditional generation project.
- Availability only: Payments are made for flexibility during the tendered time window (whether or not a specific network constraint event occurs). It is best suited to energy efficiency projects.

Table 4 – Flexibility payments

		Drayton	Coxmoor
Utilisation only	Energy price	£868/MWh (1.6-hour availability requirement)	£638/MWh (4.5-hour availability requirement)
	Capacity price	-	-
Traditional mix	Energy price	£4963/MWh	£140/MWh
	Capacity price	£150/MW/h	£38/MW/h
Availability only	Energy price	-	-
	Capacity price	£33/kW available	£69/kW available

Source: https://www.nea.org.uk/technical/scmz/

2.3 Effects / impacts

As the operational phase has not started, results are not yet known. However a process evaluation is available (SSEN, 2020; see also barriers and success factors below).

2.4 Changes over time, if any

No changes have been made yet as the project is in its initial phase.

2.5 Barriers and success factors

The main barrier for the business-as-usual application of using community-based small scale flexibility is that due to the low maturity of this market, the costs associated with the support for the communities significantly reduce the profitability of providing the service. As maturity of the market increases, the need for support is expected to be reduced (SSEN, 2020).

Main success factors identified:

- **Based on piloting**

The SCMZ initiative follows the encouraging outcomes of the Solent Achieving Value from Efficiency (SAVE) project pioneered by SSEN in partnership with the University of Southampton, DNV GL and Neighbourhood Economics from 2014 and 2019. The SAVE project, which involved 4,000 homes, tested four energy efficiency interventions to determine the extent to which energy efficiency measures can be a cost-effective, predictable and sustainable tool for managing peak and overall demand as an alternative to network reinforcement. In addition, the SAVE project produced a network investment decision tool that allows DSOs to assess and select the most cost-efficient methodology for managing electricity distribution network constraints. The process considers the effects of different types and degrees of energy efficiency interventions, as well as more traditional techniques for network reinforcements (EA Technology Ltd, 2017). The project provides a blueprint for building closer relationships with customers and local stakeholder organisations by empowering them to better control their electricity consumption and, in turn, receive lower bills and achieve carbon reductions.

- **Partnering for efficient community outreach**

SSEN formed a partnership with NEA, an organisation that has good outreach to local communities: this is a good way to build trust for the quite novel project and to mobilise potential service providers with matchmaking events and support from the idea until the tendering.

- **Can be matched with other funds**

The flexibility revenue can be matched with already available ones for energy efficiency and fuel poverty. No exclusivity requirement.

2.6 Replicability and scalability potential

SSEN invested in the SAVE pilot and these operation flexibility project areas to replicate them elsewhere in its network where congestion requires either network capacity investment or peak shaving by consumers via demand response and energy efficiency.

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3 DEMAND FLEXIBILITY IN DISTRICT HEATING NETWORKS

Country/region	EU
Type of E1st approach	A – In front / General 1 – Allowing E1st (Establishes level-playing field between supply- and demand-side resources)
Energy carrier(s) targeted	Heat
Sector(s) / energy system(s) or end uses targeted	Energy/ heat supply, households
Implementing bodies	Local authorities
Decision-makers involved	
Main objective(s)	Using ICT and utilisation of building thermal inertia for demand shifting
Implementation period	Ongoing

The aim is to improve the load factor of the households regarding heating. This has the potential to improve the attractiveness of district heating (DH) and accelerate the roll out of DH networks. Capital costs are lowered by reducing the required boiler capacity and pipework sizes. Operational costs are reduced by increasing the coverage of the primary plant and reducing heat losses and pumping energy. Shaping the heat demand and the reduction of demand peaks has the potential to improve network efficiency, integrate renewable energy sources and reduce capital costs within the network (Sweetnam et al., 2018; Mishra et al., 2019). Experimental studies on thermal peak shaving in district heating networks resulted in peak reductions between 5% and 35%, depending on the limitations of the modifications (Guelpa et al, 2019).

3.1 Background

Regulating demand is one way to tackle current and future challenges like volatile energy supply, decentralised generation and critical energy grid situations. This is usually referred to using the term demand side management (DSM) or demand response (DR). The terms imply that changes in demand happen as a reaction to the status of the grid or energy availability. The goal of DR is not necessarily the reduction of energy consumption, but the avoidance of high power costs, costs for grid expansion or backup power plants and conventional energies due to demand following generation (instead of vice versa).

That principle is used regarding electricity but is also applicable to homes connected to district heating networks or the control of electro-thermal devices (Sweetnam et al., 2018). The ICT is used to follow a demand-shaping signal/tariffs for homes in order to shape network level demand in a coordinated and fair manner by equalising the impact of changing outside temperatures. In this way, both demand profiles and network temperatures are optimised in a holistic approach.

3.2 How has the E1st principle (or similar concept) been implemented?

The Energy Efficiency First paradigm is referred to when dealing with the challenges of the energy transition and includes both energy efficiency and demand response. In the changing energy paradigm, buildings will need to be viewed as having an active role in supporting the flexibility of energy systems.

3.3 Effects / impacts

The impact of reducing peak heat demand or increasing the load factor allows a reduction in the size of the network or the decrease of operating costs: Pipes, pumps and the central plant can all be downsized, or existing networks can be expanded without additional primary infrastructure. Three main effects can be realised:

1) additional buildings can be connected to the network without installing new pipelines;
2) a better exploitation of renewable energy sources can be achieved; and
3) a reduction in the amount of heat produced by heat-only boilers can also be achieved (Guelpa et al., 2019).

The experimental study of district heating networks, where the heating in buildings was rescheduled, showed a peak reduction between 5% and 35%, depending on the limitations on the modifications (Guelpa et al., 2019).

Studies need to take into consideration the occupant's perceptions of comfort and indoor temperature, but results showed that the occupant perception of the indoor thermal environments did not deteriorate during the DR implementations. DR events may be triggered and executed without significantly impacting occupant satisfaction with the thermal comfort of the premises (Mishra et al., 2019).

3.4 Changes over time, if any

Demand-side management will play a major role in future energy systems. However, while they have been explored in some depth for electricity grids, a similar progress has not been made for district heating networks.

The European Commission's proposal of recast of EPBD (Energy Performance of Buildings Directive) on 30 November 2016 might be a necessary and logical step to integrate the readiness of buildings for DR into a regulatory framework. It introduces the "smart indicator" which rates "the readiness of the building to adapt its operation to the needs of the occupant and of the grid and to improve its performance." This regulation could facilitate and support DR in district heating.

3.5 Barriers and success factors

Most scientific publications mention the importance of respecting consumer requirements for comfort. Comfort, however, is difficult to define and measure, even for the consumers themselves. To facilitate this and allow adjustments, a user-friendly user-interface is necessary.

Generally, the shape of the heat-demand profile depends on the characteristics and habits and the type of heat delivery technology connected. These determinants need to be taken into account when trying to alter the load profile and maintain comfort.

3.6 Replicability and scalability potential

District heating might become more important in the future; it is currently ranked number 27 in Project Drawdown's 100 solutions to global warming. (Haas, 2018). Although district heating requires a long-term financial commitment that fits poorly with a focus on short-term returns on investment, it brings many advantages in comparison to individual heating systems. Usually, district heating is more energy efficient due to the simultaneous production of heat and electricity in combined heat and power generation plants. This has the added benefit of reducing carbon emissions (Dunne, 2014). Implementing DR in district heating can increase the flexibility and efficiency of the system to contribute to a sustainable use of heat.

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4 PARTICIPATION OF DEMAND RESPONSE IN FRENCH WHOLESALE ELECTRICITY MARKET

Country/region	France
Type of E1st approach	A – In front / General 2 – Enabling E1st (E1st in Network operation/Power markets)
Energy carrier(s) targeted	Electricity
Sector(s) / energy system(s) or end uses targeted	Residential / Industry / Tertiary
Implementing bodies	RTE, the French Transmission System Operator
Decision-makers involved	Demand response aggregators Industrial/Tertiary sector and individuals
Main objective(s)	The NEBEF scheme aims at organising financial flows between actors to allow for a participation of demand response on the wholesale electricity market, including by direct participation of aggregators
Implementation period	Operational since 2014

In France, the Block Exchange Notification of Demand Response mechanism, known as NEBEF[9] allows third party players (including aggregators) to offer demand response services at wholesale power markets. This mechanism was created in 2013[10] and defines the roles and obligations for the different market actors. A debated feature of the mechanism is the compensation system to electricity suppliers, who receive a payment for the electricity which was bought upfront but not consumed.

4.1 Background

Ensuring that demand response resources can access relevant power markets and compete on an equal footing with generation is part of enacting the Efficiency First principle (Enefirst, 2020).

In France, demand response has been supported by the use of dynamic tariffs since the 1960s. With the liberalisation of electricity markets, the end of some price schemes led to a reduction in the demand

[9] "*Notification d'Echanges de Blocs d'Effacement*" in French.
[10] 2013: pilot scheme; 2014: first set of rules

response volume stemming from dynamic tariffs.[11] Since 2003, a number of market mechanisms have been opened to the participation of demand response. The situation is briefly described in Box 1 below.

Box 1 – Demand response in the French electricity markets

Among the mechanisms directly managed by the Transmission System Operator (TSO) to balance electricity supply and demand in real time, the primary and secondary reserves have been open to resources connected to the transmission grid since 2014, and to those connected to the distribution grid since 2016. This resulted in the participation of demand response resources in the primary reserve.[12] The tertiary reserves have also been gradually opened to demand response.[13] Industrial sites (since 2003) and individuals (since 2007) can also participate in a balancing mechanism.[14] An interruptibility mechanism is also in place as a last resort option and is available to industrial consumers connected to the transmission network. Since 2011, annual calls for tenders[15] are organised to develop France's demand response capacity and ability to participate in the different schemes.

Demand response is also able to participate in the capacity mechanism,[16] in operation since 2017. Each electricity supplier is required to provide evidence that its customers' consumption can be covered in the peak periods. They can use capacity guarantees based on their own means of production and/or (implicit) demand response, and/or purchase (explicit) demand response or generation capacity guarantees from other operators. Capacity guarantees are issued by the TSO both to generation and demand response capacities, following a certification process. Demand response can be valued in this mechanism either explicitly by being a certified resource, or implicitly if used to shave peak demand by a supplier.

ADEME, the French energy agency, notes that the French regulatory framework is rather advanced compared to other countries (CEREN & E-Cube, 2017). Industry association SmartEn describes the French market as "an almost fully open" balancing market. The following section looks at the situation regarding the participation of demand response in wholesale power markets.

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11 The authorities expect this trend to shift with the deployment of smart meters and the revised network tariff design (MTES, 2020).
12 In 2018, the primary reserve had about 140 MW of demand response — almost 10% of this year's reserve, with a 12% average level and 20% at peaks in late 2018 (MTES, 2020). However, according to industry association SmartEn, low procurement volumes and rather large minimum bid size might affect demand response's participation on the secondary reserve (Smart En, 2018).
13 Demand response capacity participation of 530 MW on average in rapid reserves (about 50% of the contracted rapid reserve) and 45 MW in complementary reserves in 2018 (MTES, 2020).
14 In 2018, about 22.3 GWh of demand response was activated on the adjustment mechanism, for an average capacity of 727 MW deposited on the adjustment mechanism (MTES, 2020).
15 The volume targets are: 2018: 2,200 MW; 2019: 2,500 MW; 2020: 2,900 MW; 2021: 2,000 MW; 2022: 1,800 MW; 2023: 2,000 MW (MTES, 2020).
16 In 2017, demand response contributed to 2% of the capacity under the capacity mechanism (1.9 GW out of 92 GW) (MTES, 2020).

4.2 How has the E1st principle (or similar concept) been implemented?

Demand response participation in electricity markets reduces the amount of electricity and/or capacity procured and, in the long term, avoids unnecessary investment on the supply side. Demand response also benefits consumers by lowering clearing prices (i.e., lower energy bills for the same level of energy services) and allows for a larger share of variable renewables to be accommodated. Its participation in energy markets has been identified as enabling the Efficiency First principle.

In France, before 1 January 2014, demand response was only valued implicitly as part of a supplier's portfolio. With the Brottes law and the creation of the NEBEF mechanism, demand response resources can also be explicitly traded on the wholesale electricity market. This valuation depends on the wholesale prices and on the quantities actually withdrawn from consumption (not on capacity). NEBEF organises the roles of the different actors:

- All the consumption sites connected in mainland France can participate, either by contracting a third-party demand response aggregator (DRA), or directly if they have a minimum load reduction capacity of 100 kW.
- Demand response aggregators (DRAs) can sign contracts with consumption sites, including remuneration provisions, and sell "demand response blocks" on the electricity market over the counter or via day-ahead and intraday power exchanges. They do not need the authorisation from the energy supplier to activate demand response services. DRAs also have the obligation to be the Balance Responsibility Party (BRP) or to appoint a BRP for each demand response activation sold via the NEBEF mechanism.
- The transmission system operator, RTE acts as a trusted third party in charge of certifying the DRAs (who have to fulfil a number of criteria to participate in the mechanism), collecting demand response schedules from DRAs (ahead of the activation), and verifying the volume of energy actually reduced (after the activation).
- Energy suppliers of the concerned sites receive a compensation from the DRA for the electricity which was bought but not consumed based on a tariff grid established by the TSO (more information in Box 2 below). For market parties on the wholesale markets, the purchase of 1MWh of electricity produced is the equivalent of 1MWh of demand response.

Box 2 – Supplier compensation

Three compensation schemes are used.[17] The first one applies to contracts under regulated prices (a reference price[18] is set which reflects the energy share of the electricity supply price). The second one is a corrected model which applies to bigger sites in particular, and the third one stems from bilateral agreements between the Balance Responsibility Party/Supplier and the DRA.

The issue of compensation to suppliers has been the subject of a legal battle between supplier EDF and aggregator Voltalis over the fairness of the approach. The issue has also been discussed afterwards at the EU level during the revision of the EU electricity market legislation.

In its proposal of a recast of the Directive on the internal electricity market, the European Commission (2016) proposed that aggregators shall not be required to pay compensation to suppliers or generators, a proposal which was challenged[19] by Eurelectric, an organisation representing the electricity industry. It was argued that the valuation of demand response is only made possible by the fact that suppliers continue to purchase energy in anticipation of their customers' full demand.

Negotiations over the text has resulted in a compromise which states that "*Member States may require electricity undertakings or participating final customers to pay financial compensation to other market participants or to the market participants' balance responsible parties, if those market participants or balance responsible parties are directly affected by demand response activation.*"

This compensation shall however "*not create a barrier to market entry for market participants engaged in aggregation or a barrier to flexibility*" and be "*limited to covering the resulting costs incurred by the suppliers of participating customers or the suppliers' balance responsible parties during the activation of demand response.*"

The text further adds that the "*method for calculating compensation may take account of the benefits brought about by the independent aggregators to other market participants and, where it does so, the aggregators or participating customers may be required to contribute to such compensation <u>but only where and to the extent that the benefits to all suppliers, customers and their balance responsible parties do not exceed the direct costs incurred.</u>*" It is still early to evaluate how this method will be implemented by Member States (Baker, 2018).

[17] The principle of the compensation has been established by Law n° 2015-992 and is further explained in Article 9 of the NEBEF rules (RTE, 2019).
[18] Reference prices can be found on RTE's website in €/MWh, for the different types of contracts: https://www.services-rte.com/fr/decouvrez-nos-offres-de-services/baremes-versement-nebef.html
[19] See https://www.eurelectric.org/news/tapping-the-demand-response-potential-the-cost-efficient-way

The process is described by the RTE in Figure 8 below.

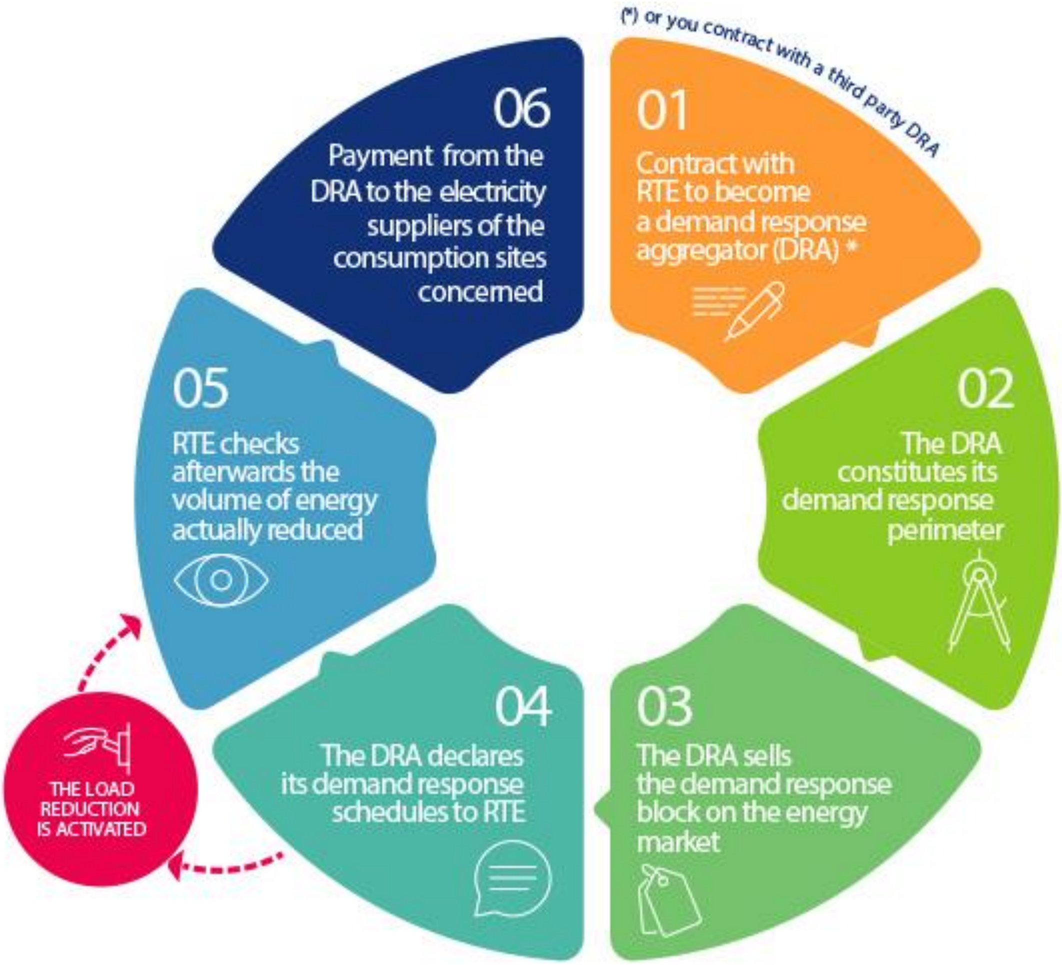

Figure 8 – The NEBEF process (Block Exchange Notification of Demand Response mechanism) (Source: RTE)

The role of the different actors is described by the French regulator, CRE in Figure 9 below.

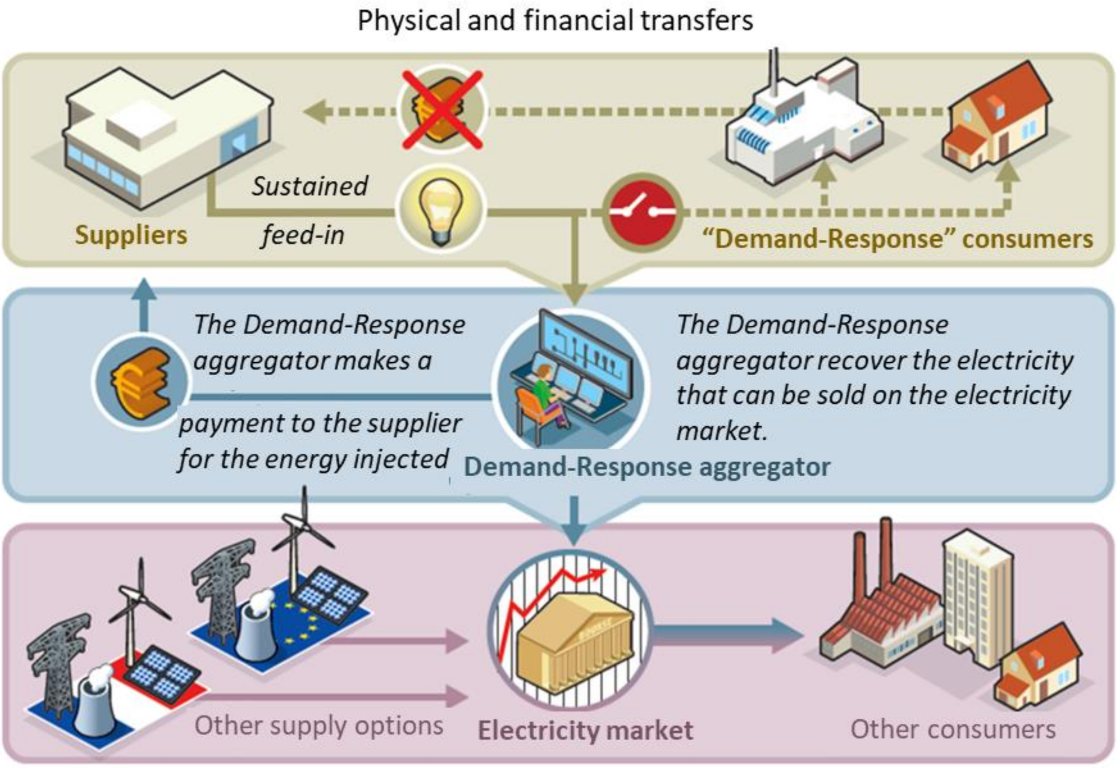

Figure 9 – How Demand Response can take part in the electricity market (Source: CRE (translated from French))

The implementation of the Efficiency First principle shall be assessed against different criteria.

First, are demand response potentials taken into account in planning? Flexibility targets are set in France's energy plan ("programmation pluriannuelle de l'énergie" currently under revision) (MTES, 2020).

Secondly, is the design of the electricity market allowing for the participation of demand response resources? Baker (2018) highlights that different barriers typically prevent the deployment of demand response in electricity markets. In France, several of these barriers were lifted and the NEBEF mechanism opens up the wholesale market to the explicit participation of demand response, which demonstrates the value of demand response beyond its capacity and balancing benefits[20] in line with Article 15-8 of the Energy Efficiency Directive (2012/27/EU).[21] In addition, demand response participants do not require the authorisation of the electricity supplier to activate demand response services. It should also be noted that

[20] For more information about the start of the scheme, see (RTE, 2013): "(…) *les dispositions qui permettent aux effacements de participer aux marchés de l'électricité, c'est-à-dire d'être pris en compte de la même façon que les autres produits parmi les outils de production mobilisés pour répondre à la demande (et non uniquement pour corriger les déséquilibres résiduels), font sens d'un point de vue économique* [the provisions that allow Demand Response to take part in the electricity markets, i.e. to be taken into account in the same way as other products among the supply/capacity options used to meet the demande (and not only to correct the residual imbalances]."

[21] Article 15-8 states that "*Member States shall ensure that national energy regulatory authorities encourage demand-side resources, such as demand response, to participate alongside supply in wholesale and retail markets*." The Article refers to both balancing and ancillary services, and to direct market participation.

the participation threshold is 100 kW for NEBEF, against 10 000 kW for the balancing mechanism. Industry association SmartEn states that the NEBEF mechanism has been “a key regulatory evolution” for developing a framework for independent aggregators, which is rated now as “quite developed” (SmartEn, 2018).

Finally, does the operation of the electricity market allow for the participation of demand response resources? On this last point, NEBEF’s assessment is mixed. The energy regulator (CRE) notes that the adjustments of NEBEF’s rules over time led to an increase in the volume and the number of actors involved.[22] Nevertheless, it is estimated that 95% of sector revenues are capacity related (MTES, 2020). A more detailed analysis of the financial results of aggregators would be needed to understand the evolution of the business models and the barriers preventing further expansion of demand response. Baker (2018), however, points that most European markets do not allow energy prices to reflect real value when resources are scarce. In such conditions, the supplier compensation mechanism (see above) can consume most or all of the revenues currently available to aggregators, seriously undermining the economics of explicit demand response and putting the associated potential benefits to customers at risk.

4.3 Effects / impacts

In 2019, 21 aggregators signed a contract with the TSO to participate in the NEBEF scheme (RTE, 2019).

Demand response volumes valued with the NEBEF mechanism reached 11 GWh in 2016 (RTE, 2017), 27 GWh in 2018 (RTE, 2019), and 22.2 GWh in 2019 (RTE, 2020). Most of the 2019 demand response came from the aggregation of small units (households or professional sites) (RTE, 2020).

4.4 Changes over time, if any

The original government’s proposal for an Energy Transition Law had foreseen a premium paid to demand response operators (in €/MWh). This premium was meant to reflect on the system benefits and improve the business case for demand response. Consumers were to support this premium through a general contribution (from the energy bill). The design of this premium was challenged[23] by consumer associations who claimed it would not reflect the system benefits appropriately and would create competition distortion. Competition authorities also criticised the scheme, which has not yet been implemented. Debate related to the implementation of the Directive on common rules for the internal market in electricity might revive discussions.[24]

The Energy Transition Law of 2015 foresees a different compensation mechanism for certain DRA, under certain circumstances. In such cases, RTE could partially pay the compensation of the BRP/supplier of the site providing demand response services. Decrees and implementation acts, however, remain unpublished.

[22] Energy regulator website: https://www.cre.fr/Electricite/Reseaux-d-electricite/Effacements
[23] For explanation of the consumer association position, see (in French) https://www.quechoisir.org/action-ufc-que-choisir-electricite-l-ufc-que-choisir-saisit-le-conseil-d-etat-pour-effacer-la-prime-d-effacement-n12863/
https://www.quechoisir.org/actualite-effacement-electrique-diffus-le-gouvernement-s-obstine-aux-depens-des-consommateurs-n23245/
[24] For proposals on how to implement Article 17 of the Directive on common rules for the internal market in electricity, see Baker (2018).

The government considers that such a scheme would require the notification of the Commission with respect to State Aid regulation.

4.5 Barriers and success factors

The government is committed to organising additional tenders for demand response in case objectives defined in the energy plan are not achieved.[25]

The NEBEF scheme is relatively recent and has to be evaluated in the context of the overall framework for demand response in France. The French authorities have recently proposed to adjust the 2023 flexibility objective downwards[26] and provided a number of reasons for missing the target which was originally set, including a lack of maturity in the sector. It is unclear whether the overall organisation of the electricity market is in question.

Although this has not been explicitly brought forward by the authorities, the issue of the valuation of system benefits and the remuneration of demand response for bringing these system benefits remains open.

4.6 Replicability and scalability potential

Several measures are being examined to further promote demand response in France. This includes improving and simplifying the support framework for demand response to best meet the needs of the sector (MTES, 2020). MTES is working on a significant reform of this mechanism to allow for greater volumes. The new mechanism will require a notification at the Commission's DG Competition (for State Aid).

There is a large untapped opportunity to replicate the approach in the EU. Indeed, SmartEn (2018) has identified a number of Member States which are lagging behind in terms of valuing demand response in electricity markets. Regulatory safeguards already in place in France could serve as a good starting point for countries planning to rely on demand-side resources more in the future.

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[25] This tender (open for around 2 GW) in 2018 and 2019 ended up with roughly 700-800MW.
[26] 4,5 GW in 2023 against 6 GW in the initial plan.

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5 ENABLING RULES FOR DEMAND RESPONSE AGGREGATORS

Country/region	EU
Type of E1st approach	A – In front / General 2 – Enabling E1st (Establishes level playing field between supply- and demand-side resources)
Energy carrier(s) targeted	Electricity
Sector(s) / energy system(s) or end uses targeted	Grids and providers of flexibility, energy supply
Implementing bodies	National regulators
Decision-makers involved	TSO/ DSO/ new market roles (aggregators)/ energy suppliers/ DR suppliers
Main objective(s)	The integration of renewable energy can be enabled by a flexible demand following the intermittent supply. The pooling of responsive demand requires appropriate market rules that enable – among others — the efficient operation of aggregators.
Implementation period	Ongoing

Many renewable electricity sources are intermittent. The integration of wind and solar power can be enabled by the activation of flexible demand. Germany is an example with a medium developed market for flexible energy where recent improvements as well as barriers can be pointed out; the development and further regulatory issues are described.

5.1 Background

Regulating demand is one way to tackle current and future challenges like volatile energy supply, decentralised generation and critical energy grid situations. This is usually referred to with the terms demand-side management (DSM) or demand response (DR). The terms imply that changes in demand happen as a reaction to the status of the grid or energy availability. The demand flexibility can be either market-driven (e.g., to use unforeseen renewable electricity generation) or grid-driven (e.g., congestion management). The goal of DR is not necessarily the reduction of energy consumption but the avoidance of high power costs, costs for grid expansion or backup power plants and conventional energies due to demand following generation (instead of vice versa). To make use of smaller loads and to integrate them into the balancing, wholesale or capacity market, an aggregation is necessary to meet the participation criteria. Aggregators are players who trade and supply energy without managing their own balancing groups. Their business model consists primarily of pooling and marketing generation facilities, flexible consumers and storage systems. They scale small plants or flexible loads to a tradable volume and represent these pooled resources as a single unit at the markets.

5.2 How has the E1st principle (or similar concept) been implemented?

The Energy Efficiency First paradigm is referred to when dealing with the challenges of the energy transition and explicitly includes both energy efficiency and demand response as supporting the integration of renewable energies (ECF, 2016). The share of renewable energies is increasing, but future challenges will involve more than just adding more renewable energies quickly to the system. A secure and stable supply needs interlinkage of processes, i.e., interaction between power plants and renewable energies, flexible demand and storage and consumption. In the European Network Codes (European Commission, 2009), the Energy Efficiency Directive (European Commission, 2012) and the Commission's Energy Union Communication (European Commission, 2015), demand response is mentioned as an enabler of the integration of renewable energies and the security of supply. The aim is to use demand-side flexibility and integrate market players, including consumers. The integration of the DR potential of single market players needs to be structured and organised. Aggregators bundle the resources that can be traded at the flexibility markets. To do so, the rules for participation and interactions with other players like energy suppliers and TSOs need to be defined.

5.3 Effects / impacts

The Electricity Balancing Guideline (EB GL, Commission Regulation (EU) 2017/2195) sets out EU-wide rules governing the functioning of the load balancing mechanism. Europe has made important progress towards streamlining market conditions and improving access for innovative technologies and services that are essential for success in the sustainable energy transition. Although markets are opening up, the progress is still slow and varies by European country (SmartEn, 2018).

Italy and Germany have made strong efforts towards opening the balancing markets, although they started from a weak position with a market that was restrictive regarding participation with smaller loads or specific technologies/appliances. Other countries like Great Britain and France developed frameworks and innovative solutions earlier. Smart Energy Europe (2018) provides an overview of the status of different European countries and their development in the balancing markets and regulatory frameworks. Only a few countries (e.g., France and Belgium) have a well-developed aggregator framework. The Netherlands's framework is not accompanied by the expected aggregator activity, although includes welcoming technical requirements.

An opening of the balancing markets would let the DR providers enter the market. Companies have high loads and energy consumption to contribute to load balancing and the integration of volatile renewable energies. In Germany, for example, only a few energy-intensive industrial companies participate in the market so far, and no companies from the service sector participate. The potential of the industrial sector is estimated to about 1-12 TWh of flexible energy and about 3-5 GW of peak power; the potential of the service sector falls within a comparable absolute range but is distributed over more companies with a smaller potential each. The flexible technical potential of the service sector is estimated to be about 4 TWh, and 1 TWh is estimated to be the flexible practical potential (the potential of the companies willing to participate at the current state; Wohlfarth et al., 2020). Taking into account that the practical potential is always lower than the technically feasible potential, more favourable framework conditions that facilitate market access could significantly increase this practical potential. This is especially relevant as the service sector has not yet had the opportunity to enter the markets (i.e., due to regulatory barriers) which could be enabled by aggregators. Electricity consumption at the household level points to the potential here, too, with heat pumps and electric vehicles as particularly promising technologies. However, the potential here is spread across households, and special electricity tariffs are typically offered for these applications.

5.1 Changes over time, if any

Within the last years, the market integration of DR and the definition of roles like the aggregator developed. When rating energy markets in terms of their degree of consumer participation, programme requirements, standardised verification and measurement as well as payment and risk structures, Germany is only ranked as "partially open," while other European countries (e.g., Belgium, France, Great Britain and Switzerland) already count as "commercially active" (SEDC, 2017).

On Germany's balancing market and under the Ordinance on Interruptible Load Agreements (AbLaV), flexible loads need to prequalify to fulfil minimum standards. The balancing market is split into three submarkets: the primary, secondary and minutes reserve market. Bid sizes and reaction times vary between 1 and 5 MW and from seconds to 15 minutes, respectively. The interruptible loads act (AbLaV) was issued in 2012 and revised in 2016. It allows transmission system operators to advertise their needs for sheddable loads for balancing or redispatch. In total they tender 750 MW of immediately sheddable loads (reaction time within seconds) as well as of quickly available loads (max. 15 minutes reaction time). To open the market to more customers, bid sizes and bidding cycles have recently been adapted (SEDC, 2015, SmartEn, 2018). Since the revisions, pooling of loads is also permitted, e.g., by third party actors like aggregators, as is the participation of medium voltage grids, thus facilitating participation for smaller customers and smaller loads. A standardised process (aggregator model) for contracting and financial compensation between the parties is currently in the works and has been thoroughly discussed by the German regulatory agency Bundesnetzagentur (BNetzA, 2016, 2017) and other relevant stakeholders. The challenges faced in untying the DR potential in the German case are used to provide recommendations for other countries as well, e.g., in Chile (Valdes et al., 2019).

5.2 Barriers and success factors

Regulatory barriers in particular often hinder market growth and there is a lack of clarity concerning market roles and responsibilities, especially for load aggregation. Currently, low prices for flexible demand inhibit participation even if aggregation is an option. In Germany, one example of current regulations that essentially counteract the participation in demand resources to balance the grid is the StromNEV (2005, §19, sec. 1 and 2). According to this, consumers that has their peak outside the pre-defined peak period of the network (and the given voltage level) and has a high load are eligible for a special demand/capacity network tariff. They get up to 80% reduction of the default rate if they keep their peak outside these network peak period. Thus, their availability for DR is limited to the hours outside the network peak period: the revenue they would get from DR that involved the peak period would most probably less than the extra cost of losing the privilege for the reduced demand tariff.

Clarity of regulation, incentives and information about the options involved are essential to promote DR participation. In Germany, for the aggregation of loads, contracts are necessary with the balancing responsible party and with the transmission system operator. Currently, the main barrier to balancing market participation of DR is that there are no standardised processes and contracts for the settlements between aggregators, balancing group managers and suppliers. Although the German regulatory agency Bundesnetzagentur (BNetzA) and other relevant stakeholders are discussing standardisation (the "aggregator-model"), in particular for quantifying balancing and financial compensation between aggregators and balancing group managers (cf. BNetzA, 2016).

A individual prequalification of each participant/flexible appliance is still required in Germany. In France and Switzerland, for example, pooling is permitted and prequalification conditions only need to be fulfilled by the pool as a whole; this facilitates the participation of smaller flexibility providers, so that flexible loads of any size and without restrictions in terms of technical requirements can participate in the rule market. The principle of aggregation in France works as follows: Suppliers receive a premium to compensate for lost deliveries. For reasons of confidentiality, all relevant processes, such as the transfer of data or payment of premiums, are coordinated by RTE (Réseau de Transport d'Electricité) as an independent body. Aggregators generate revenues by marketing flexibility on the spot market, while flexibility buyers receive a premium negotiated with the aggregator (Eßer et al., 2016).

5.3 Replicability and scalability potential

The system would profit from a harmonisation of market rules to facilitate the trade of flexible demand over the borders of European countries. Eßer et al. (2016) discusses the opportunities of cross-border trading of flexible loads. Besides the rules and regulations of aggregation, rules for a cross-border trade also need to be defined.

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6 DECOUPLING UTILITY SALES AND REVENUES

Country/region	United States, EU
Type of E1st approach	A – In front / General 2 – Enabling E1st (Regulation)
Energy carrier(s) targeted	Natural gas, electricity
Sector(s) / energy system(s) or end uses targeted	Generation / transmission / distribution
Implementing bodies	Regulators/governing boards, utilities
Decision-makers involved	Utilities
Main objective(s)	Remove disincentives for regulated electricity and natural gas utilities to promote energy efficiency and other demand-side resources
Implementation period	1982 – ongoing

Utilities are responsible for providing customers with reliable and reasonably priced energy services. However, under traditional regulation, utilities – such as electricity and gas network operators – are discouraged from investing in cost-effective energy efficiency because it lowers their revenues. An established way to remove this conflict is to break the link between the utility's revenue and the amount of energy it sells or transmits in order to ensure that the utility recollects its capital expenditures and operating expenses plus an authorised return on investment, no less and no more. In combination with other regulatory mechanisms, such decoupling mechanisms can induce utilities to help customers save energy whenever it is cheaper than producing and delivering it (Sullivan et al., 2011).

6.1 Background

In traditional utility regulation, the regulator (for investor-owned utilities) or governing board (for publicly-owned utilities) determines the amount of revenue the utility needs to collect from customers to recover its costs of maintaining and investing in the system's wires, pipes and generators – including, for investor-owned utilities, a reasonable return on investment. The regulator or governing board then divides this authorised revenue by the amount of energy it expects consumers to consume, and establishes a tariff ($/kWh) (NRDC, 2012). These tariffs are then part of the price customers pay per unit of electricity or gas used. With the tariffs set, the utility's actual revenue depends on the amount of energy customers use, i.e., sales (NARUC, 2007).

Setting tariffs is conducted every few years in so-called tariff proceedings. Between proceedings, utilities' ability to recover their costs is based on sales (NARUC, 2007). While the extent of energy use is anticipated in the tariff proceeding, actual sales will almost always differ due to complex variables (e.g., weather, changes in economy, demographic shifts, new end-use technologies). As a result, the utility will either earn more or less on electricity and gas than had been assumed during the tariff proceeding (NARUC, 2007). When sales are higher than anticipated, utilities may collect more revenues than their expenses and reasonable return, leading to increased profits.[27] This reflects a throughput incentive for the utility, i.e., increased sales leading to increased profits. In turn, it is a disincentive for utilities to invest or engage in anything that decreases sales, such as energy efficiency programmes, distributed renewable energy generation and other demand-side resources – even if these are cost-effective to meet customer needs (NRDC, 2012). The throughput incentive does not only contribute to utility inaction on energy efficiency, there are cases where utilities have actively countered efficiency measures in their service area to promote sales (Sullivan et al., 2011).[28]

Overall, under this traditional regulation, the customer loses in two ways. When sales fall, the utility may not recover all its costs and will have to go through costly litigated regulatory proceedings to do so, which customers pay for. When sales increase, utilities may collect more than their authorised costs and reasonable return, creating windfall profits at customer expense. In either case, customers lose the economic benefits they would have enjoyed if the utility invested in cost-effective demand-side resources (NRDC, 2012). Regulators can solve this problem by implementing decoupling mechanisms that adjust tariffs to ensure a utility collects the costs its regulator or governing board authorises, no less and no more. Combined with other regulatory policies, such decoupling mechanisms can free utilities to help customers save energy whenever it is cheaper than producing and delivering it (NRDC, 2012).[29]

In practice, decoupling does not change the traditional tariff proceeding procedure but, in its simplest form, adds an automatic adjustment to tariffs between tariff proceedings based on over- or under-recovery of authorised revenues. Similar to traditional tariff proceedings, tariffs are set by determining the revenue requirement and dividing by expected sales. Then, on a regular basis, tariffs are re-computed to collect a target revenue based on actual sales volumes.[30] This means that if sales increase, tariffs drop in the next period; if sales decrease, tariffs increase to compensate. Overall, these regular tariff adjustments between tariff proceedings break the link between (or *decouple*) a utility's revenue and sales by either restoring to the utility or giving back to customers the money that was under- or over-collected as a result of fluctuations in retail sales. This ensures that utilities (NRDC, 2012):

- recover only the costs that were approved by their regulator or governing board.

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[27] The underlying assumption being that for existing customers, sales growth does not require a great deal of new infrastructure (e.g., generators, transmission and distribution lines, substations). In these cases, utilities' fixed costs would not increase with increased sales, thus translating into increased profits (NARUC, 2007).

[28] Measures pursued by utilities include a) providing incentives for the use of inefficient equipment or practices, such as electric resistance heat, b) opposing highly cost-effective efficiency codes for new buildings, c) failing to include energy efficiency in their communications with customers (Sullivan et al., 2011).

[29] Decoupling is only one mechanism within a broad portfolio of regulatory mechanisms subsumed under the term performance-based regulation (PBR). Broadly speaking, PBR provides utilities with a regulatory framework that encourages better performance, such as enhanced energy efficiency within its service area. Besides decoupling (also referred to as *revenue cap regulation*), other PBR mechanisms include price cap, incentive-based and yardstick mechanisms (Lazar, 2014).

[30] Usually, tariff reconciliations are made at least on an annual basis to compensate for under- or over-collection of fixed costs during the previous year. Note that this is different from traditional tariff-making in which there is little oversight of revenue between tariff proceedings and often several years go by before tariffs are realigned with actual revenue requirements (NRDC, 2012; Sullivan et al., 2011). For example, tariff proceedings for California's Pacific Gas and Electric Company are only held every three years (Midgen-Ostrander et al., 2014).

- cannot make windfall profits by encouraging higher sales.
- are not penalised when demand-side efforts reduce sales.

All in all, decoupling mechanisms can remove disincentives for regulated utilities to promote energy efficiency and other demand-side resources, but they are not designed to provide actual incentives since they provide lost margin recovery, not a reward (Lazar, 2014). To provide distinct incentives for the update of energy efficiency and other demand-side resources, decoupling needs to be part of a package of regulatory policies. Most notably, this includes a) timely and full recovery of the cost of demand-side programmes, and b) providing incentives for utilities to reward energy efficiency and ensure that investments in cost-effective energy efficiency opportunities are as attractive over time as alternative investments in infrastructures (CNEE, 2016; NARUC, 2007; NRDC, 2012; Pató et al., 2019).

6.2 How has the E1st principle (or similar concept) been implemented?

The idea of decoupling a utility's revenues from its sales to foster demand-side investments is not new. In fact, it has been implemented in some parts of the U.S. for decades.[31] In recent years, regulators around the U.S. have increasingly adopted decoupling mechanisms to support investment in demand-side resources (Lazar, 2014; NRDC, 2012). Figure 10 shows the status of decoupling in the 50 U.S. states as of 2019. At least 26 states have adopted some form of decoupling for electric utilities, natural gas utilities or both (NRDC, 2012).

[31] The first state to enact decoupling mechanisms was the state of California with its 1982 *Electric Tariff Adjustment Mechanism* (ERAM) issued by the state's public utility commission. The ERAM required utilities to track the difference between actual and forecasted revenues. Over-collections were refunded to consumers while under-collections were recovered by subsequent tariff adjustments (NRDC, 2012).

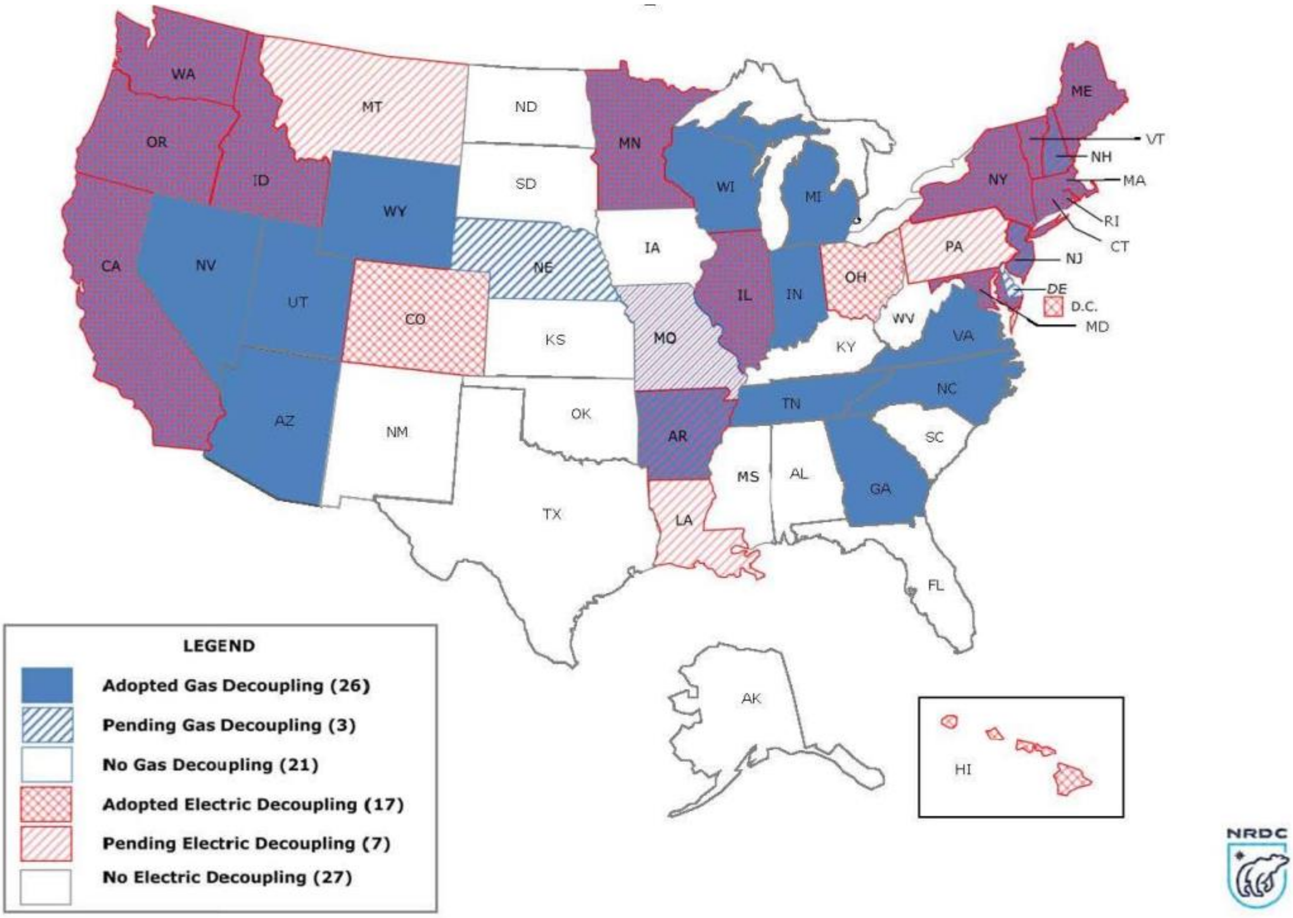

Figure 10 – Gas and electric decoupling in the U.S., as of January 2019 (Source: NRDC, 2012)

6.3 Effects / impacts

In general, due to their ongoing implementation over decades as well as the multitude of accompanying regulatory and financial policies, it is methodically difficult to determine the distinct effect of decoupling mechanisms on the ramp-up of energy efficiency and other demand-side resources. However, a range of observations can be made. According to Sullivan et al. (2011), in 2010, seven of the 10 U.S. states with the highest per capita investment in electric energy efficiency programmes and eight of the 10 states with the highest per capita investment in natural gas energy efficiency programmes had decoupling mechanisms in place. On another note, decoupling measures taken in the states of California, Oregon, Washington, Wisconsin, Michigan, and Hawaii and the region of New England have produced significant improvements in energy efficiency without harming the financial conditions of the utilities (Lazar, 2014).

Referring back to the example of California, utilities significantly increased their energy savings over time. Between 2001 (when decoupling and other supportive policies had been reinstated) and 2010, they increased their investments in efficiency nearly five-fold to over 3% of revenues – and achieved significant increases in energy savings. In addition to providing efficiency programmes for customers, California investor-owned utilities have been instrumental in the adoption of more stringent codes and standards at the state and federal level, including the state's TV efficiency standards that are projected to save 6,500 GWh annually by 2020 (Sullivan et al., 2011). Overall, as argued by Midgen-Ostrander et al. (2014), the implementation of decoupling mechanisms may be viewed as successful if the utility is no longer concerned about increases and decreases in sales, is no longer taking actions to increase sales or reduce decreases in sales, and is improving the overall efficiency of its operation and management.

Besides effects on energy efficiency, decoupling mechanisms have been evaluated with regard to their impact on customer bills. Experience shows that in the short run, tariffs for all customers under decoupling may increase when efficiency reduces sales because the utilities have to cover their costs and necessary returns on investment. However, any tariff increases would be small, particularly when compared to benefits for customers engaging in energy efficiency programmes. In some U.S. states evaluated (New York, California, Oregon), fluctuations in tariffs between tariff proceedings were less than 1% for most years and never exceed 4% (NARUC, 2007; NRDC, 2012). In another evaluation of decoupling mechanisms operating between 2000 and 2009 in 45 U.S. utilities, most often adjustments of less than $1.50 per month for residential gas consumers and less than $2.00 per month for residential electric customers occurred (Lesh, 2009). Overall, this is in an order of magnitude less than the size of adjustments customers regularly see from pass-throughs of fuel or purchased power costs (Sullivan et al., 2011).

6.4 Changes over time, if any

As stated, California was the first U.S. state to adopt decoupling. By 1982, the California Public Utilities Commission (CPUC) put decoupling in place for its three major investor-owned utilities – Pacific Gas and Electric Company (PG&E), Southern California Edison and San Diego Gas & Electric (Midgen-Ostrander et al., 2014). Although the CPUC determined that the mechanism would eliminate disincentives to promote energy efficiency and also be fair to consumers, it was suspended in 1996 as part of the state's now-infamous experiment in deregulation or electric restructuring (Sullivan et al., 2011). However, it was one of the first policies reinstated in 2001 in the wake of the Western Energy Crisis. By early 2005, every major investor-owned utility in California had decoupling in place again. As part of this, California made cost-effective energy efficiency a priority energy resource. Aggressive energy savings targets were set, complemented by a "shared-savings" mechanism providing financial incentives for utilities if they do a good job saving customers money through energy efficiency, and penalties for poor performance (Midgen-Ostrander et al., 2014; Sullivan et al., 2011).

6.5 Barriers and success factors

One concern related to decoupling is the question of whether it shifts risk from the utility to customers (Sullivan et al., 2011). This is illustrated by the situation in the state of Maine in the 1990s. The state had pioneered a decoupled tariff design with the utility Central Maine Power in 1991 but faced an economic recession at the same time. The recession resulted in lower electricity sales than anticipated in the tariff proceeding, with the decoupling mechanism taking effect to reflect pre-recession target revenues for the utility. This caused tariffs to go up when customers were least prepared to pay them, causing customer deferrals to accumulate steadily. As a result, decoupling became increasingly viewed as a mechanism that was shifting the economic impact of the recession from the utility to consumers, rather than providing the intended incentive for demand-side investments. Note that in this case, decoupling wasn’t the problem; the economic downturn was the problem. In traditional regulation without decoupling, price increases set in tariff proceedings would have reflected the same economic circumstances, only with greater delay

(NARUC, 2007; Sullivan et al., 2011). To alleviate the effects of economic downturns and other factors on sales beyond a utility's control, some U.S. states have established normalisation mechanisms that can be used to eliminate risks or assign them properly (NARUC, 2007).

Another issue with decoupling is that it can encourage utilities to take cost-cutting steps that might hurt system reliability, safety and customer satisfaction. Since decoupling tells the utility that its revenues will not be affected by sales, the only way for the utility to increase earnings is to reduce expenses and capital additions. For this reason, decoupling is generally paired with a service quality index mechanism so that any diminishment in the quality of service will be penalised (Lazar, 2014).

6.6 Replicability and scalability potential

In principle, decoupling mechanisms are neither difficult to design nor complex to administer. In its basic form, decoupling is simply a system of regularly adjusting tariffs to ensure a utility's actual revenues match its authorised revenues to recover its operating costs plus a reasonable return on investment. In the U.S. context there are numerous examples of currently successful mechanisms that regulators and governing boards can use as models (Midgen-Ostrander et al., 2014; Sullivan et al., 2011). Also, decoupling requires staff to take only ministerial action to perform a simple true-up comparison of actual revenues to the allowed revenues and adjusting tariffs to return or recover any over- or under-collection the following period (Sullivan et al., 2011).

In terms of sectors, decoupling is applicable to both electricity and natural gas utilities. While both sectors share similar cost structures that are dominated by high fixed costs, they face different underlying trends in terms of customer revenues. The gas sector tends to face declining average revenues per customer over time, leading to revenue and profit erosion between tariff proceedings in traditional tariff making. In turn, the electricity sector anticipates increasing average revenues per customer that would result in increasing profits in traditional tariff making. For these reasons, gas utilities have tended to be more open to implementing decoupling mechanisms than have electric utilities (NARUC, 2007). However, in response to longer-term expectation about expenses and environmental costs, a small but growing number of electric utilities in the U.S. have either implemented, requested, or are investigating decoupling (see also Figure 10).

Concerning applicability to the EU context, decoupling mechanisms (in the European context generally referred to as revenue-cap regulation) are in fact already to a large extent applied to the regulation of electricity network operators. The legal basis for this is essentially provided by Article 15.4 of the Energy Efficiency Directive (EED) (2012/27/EU) and its recent amendment (2018/2002) which requires Member States to introduce regulatory policies similar to decoupling for transmission system operators and distribution system operators in the electricity sector. In addition, Article 18.8 of the new Electricity Market Regulation (2019/943) strengthens the role of performance-based network regulation for DSOs. Accordingly, the majority of EU Member States have decoupling (revenue cap) mechanisms in place for the regulation of DSOs in the electricity sector, including Germany, France, Great Britain and Spain (Pató et al., 2019).

However, no equivalent legal provision exists for natural gas TSOs and DSOs in the EU (Bayer, 2015). A practical point of intervention could be the Natural Gas Directive (2009/73/EC). In Article 40 (d), the Directive lists, among others, other objectives of Member States' regulatory bodies as "helping to achieve, in the most cost-effective way, the development of secure, reliable and efficient non-discriminatory systems that are consumer oriented, and promoting system adequacy and, in line with general energy policy objectives, energy efficiency as well as the integration of large and small scale production of gas from renewable energy sources and distributed production in both transmission and distribution networks." Adding further provisions could help strengthen the standing of decoupling/revenue cap regulation in the natural gas sector – given that, at present, at least four Member States still have traditional cost plus-based regulation in place for gas TSOs and DSOs while only 15 Member States have adopted decoupling mechanisms (CEER, 2020).

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7 REPLACING A POLLUTING POWER PLANT WITH BEHIND-THE-METER RESOURCES

Country/region	Oakland, California, United States
Type of E1st approach	B – In front / Investment 2 – Enabling E1st (Substituting a retiring gas unit calling on the participation of distributed resources, including energy efficiency and demand response)
Energy carrier(s) targeted	Electricity
Sector(s) / energy system(s) or end uses targeted	All
Implementing bodies	Pacific Gas and Electric Company (PG&E) East Bay Community Energy (EBCE) Bidding organisations
Decision-makers involved	Public Utilities Commission of the State of California (CPUC) (regulator) California Independent System Operator (CAISO)
Main objective(s)	Ensure adequacy between electricity demand and supply
Implementation period	From mid-2022

The Oakland Clean Energy Initiative (OCEI) aims to address the retirement of a 165 MW fossil-fuel peaking plant[32] while avoiding the need for building new transmission lines and keeping costs down. The mix of resources selected for contributing to the project include demand-side resources (energy efficiency and demand response) as well as distributed generation (photovoltaic) and storage. The selected resources are expected to be operational in mid-2022, when the fossil-fuel plant retires.

7.1 Background

California Independent System Operator (CAISO) is a nonprofit public benefit corporation in charge of operating the wholesale energy market and maintaining reliability on the high-voltage, long-distance power lines for the grid serving 80% of California and a small part of Nevada.[33] Each year, CAISO goes through a transmission planning process to identify system limitations and opportunities for improving reliability and efficiency. The outcome of the process is called the ISO Transmission Plan.[34]

[32] The plant runs on jet fuel. For more information see EBCE, 2018.
[33] More information here: http://www.caiso.com/about/Pages/default.aspx
[34] More information here: http://www.caiso.com/planning/Pages/ReliabilityRequirements/Default.aspx

During the 2015-2016 planning process, CAISO identified a long-term reliability concern for the East Bay Area[35] (CAISO, 2016). The retirement of the 40-year-old Oakland Dynegy power plant, planned for 2022, is a risk to local transmission reliability. Once the plant is retired, peak electricity supply will need to come from other areas, causing a stress on the transmission infrastructure. This is a concern for CAISO, which controls the development and maintenance of the transmission system. CAISO is currently engaged in a Reliability Must Run contract with Dynegy, which means that the plant commits to supply electricity during periods where it is most needed.

As noted by Chhabra (2018), the “standard procedure” would be to repower the retiring power plant with new gas turbines or to install high-power transmission lines through Oakland. The first solution would mean further pollution and greenhouse gas emissions, while the second solution would require digging through a heavily populated area.

7.2 How has the E1st principle (or similar concept) been implemented?

When dealing with reliability issues, demand-side resources are potentially cheaper options from a total system perspective than building new peaker plants or transmission lines. They also bring other benefits to the economy (local job creation, etc.) and the environment. Well-designed energy efficiency and demand response programmes can contribute to lowering peak demand for energy, which is a major determinant of the size of the power system and has a large influence on its cost. Mainstreaming demand-side solutions to address reliability issues is therefore a key strategy to enable the E1st principle (Enefirst, 2020).

To deal with the planned retirement of the Oakland peaker plant, CAISO said it would consider alternatives including a portfolio of local clean resources, in line with its policy on the consideration of alternatives to address local needs in transmission planning (CAISO, 2013). The Pacific Gas and Electric Company (PG&E), which is a regulated investor-owned utility providing services in this area, has worked with CAISO to analyse how distributed clean energy resources could become part of an alternative to the plant. This resulted in the Oakland Clean Energy Initiative (OCEI), which was approved by CAISO in March 2018 (PG&E, 2018).

The project’s scope is outlined in the 2017-18 Transmission Plan (CAISO, 2018). It combines substation upgrades, in-front-of-the-meter energy storage, and the competitive procurement of an additional 10 MW-24 MW of alternative resources. CAISO’s Transmission Plan presents the OCEI elements, as well as the alternatives which have been considered, but rejected, during the planning process (Table 5).

Table 5 – Scenarios considered to meet the reliability concern and associated costs

Scenario	Description	Estimated Capital Cost 2022 $M	Total Cost 2022 $M
OCEI ***(selected***	• Upgrades to Moraga 230/115 kV Transformer Bank and at Moraga 115 kV and Oakland X 115 kV substation buses • Transmission line rerates on Moraga-Claremont 115 kV Lines #1	56 - 73	102

[35] Covering cities in Alameda and Contra Costa counties, including Concord, Berkeley, Oakland, Hayward, Fremont and Pittsburg.

scenario)	and #2 • A minimum of 10MW / 4 hour of in-front-of-the-meter utility-owned energy storage within Oakland C and Oakland L 115 kV substation pocket • Competitive procurement of additional 10 MW-24 MW of preferred resources sited within the Oakland C and Oakland L 115 kV substation pocket (at least 19.2 MW must be load-modifying in nature) • Continued reliance on transferring Alameda Municipal Power load from Cartwright (North) to Jenny (South) during peak loading conditions and after an N-1, in preparation for an N-1-1		
115 kV (scenario not selected)	• Three alternatives (Moraga-Maritime 115 kV Line Installation, Moraga-Oakland 'C' 115 kV Line Installation or Moraga-Oakland 'L' 115 KV Line Installation)	193 - 217	367
230 kV (scenario not selected)	• Submission from Next Era Energy Transmission (NEET) West: new 230 kV line from Moraga or Sobrante to Oakland C substation with a 230/115 kV transformer connecting to Oakland C 115 kV substation • Additional upgrades would need to be added to alternative to address the reliability need identified	316	574
Generation (scenario not selected)	• 200 MW of generation	232	368

(Source: based on CAISO, 2018, pp.128-129)

OCEI stands out in terms of the associated costs. It also contributes to reaching environmental objectives, notably by allowing an increased penetration of renewable energy.

Following the approval of the plan by CAISO, PG&E in collaboration with the public power supplier East Bay Community Energy (EBCE) opened a request-for-offers process in 2018. EBCE solicited resource adequacy from clean resources and PG&E sought local transmission-related reliability needs. The Solicitation Protocol (PG&E and EBCE, 2018) lists the resources which can participate in the bid. It identifies needs for peak day hourly resources (Figure 11). To mitigate against potential contingency overloads, PG&E seeks resources that reduce electrical consumption or increase generation between 8:00 am and 6:00 pm.

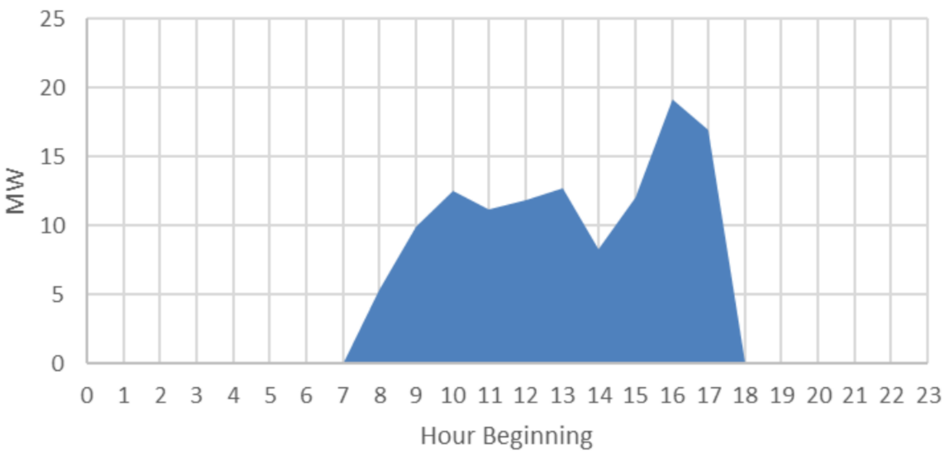

Figure 11 – OCEI Peak day hourly resource need
(Source: PG&G and EBCE, 2018)

7.3 Effects / impacts

The Oakland Clean Energy Initiative has a forecasted in-service date of mid-2022. PG&E said that it has received “multiple, competitive bids” (Morris, 2019).

A distributed storage project has been selected. Sunrun is planning to install batteries in more than 500 low-income households in and around Oakland, providing several MW of solar and more than 2 MWh of batteries by 2022. This will deliver 500 kilowatts of grid reliability capacity to EBCE during a 10-year contracted period (Sunrun, 2019). Sunrun will use a state subsidy programme which requires that savings from the solar panels are passed on to low-income tenants (Tepperman, 2019).

Utility storage projects are also being developed,[36] and it is interesting to note that Vistra Energy[37] has acquired the Oakland Power plant (which is meant to retire in 2022) and will build a battery energy storage project of 20 MW/80 MWh on the site. The system will draw electricity from the grid during off-peak hours and discharge it during peak hours (EBCE, 2019a).

The OCEI is still evolving, as shown in the next paragraph.

7.4 Changes over time, if any

CAISO (2019) requested some changes in the project as part of the 2018-2019 transmission planning process. The granularity of the project was improved.[38] CAISO also recommended that the utility-owned

[36] See also: esVolta (contracting entity Tierra Robles Energy Storage, LLC), a storage project under development, which will provide 7MW/28MWh of local resource adequacy for a period of 10 years, and will help to address the transmission-related reliability needs (EBCE, 2019b).
[37] Vistra is also developing a large energy storage system in Moss Landing, California.
[38] Out of the total resource mix (20 MW/120 MWh) to be sited within the Oakland C and Oakland L 115 kV substation pocket, no less than 7 MW/28 MWh should be either located at the Oakland L substation or interconnected via the PG&E distribution system to the CAISO-controlled grid at Oakland L. This adjustment was mentioned by PG&G during the planning process (PG&E, 2019a).

energy storage project should no longer be required to serve as a transmission asset. On this point, the staff of the California Public Utilities Commission (CPUC) provided comments during the planning process (CPUC, 2019a), requesting additional information regarding the permitted revenue streams for the energy storage component of the OCEI. They asked whether the energy storage component must function as a dedicated transmission asset, recovering capital investments only through the transmission rate case, or if the storage could also access other market revenue streams.

During the 2019-2020 planning process, which is ongoing at the time of writing, PG&E (2019b) requested confirmation that OCEI is still necessary to provide near-term reliability and requested that CAISO identify the location and amounts of any additional resource requirements associated with the incremental load growth in the new forecast. PG&E expects CAISO to "*facilitate a coordinated, phased transition and termination of the Reliability Must Run (RMR) agreement with the Vistra Oakland Power Plant, in tandem with the new OCEI resource additions*." In their comments, the staff of the CPUC (2019b) supported an evaluation of the potential for increased distributed energy resources procurement to meet the evolving needs in the OCEI project area.

The modifications in the project shows that reliability planning is a meticulous exercise, which requires adequate planning, technical capacities and frequent revisions.

7.5 Barriers and success factors

Effective communication with all stakeholders is important to build confidence and ensure the success of such an initiative. This is confirmed by recent developments reported in local media (Tavares, 2019). In November 2019, the Alameda City Council directed its city attorney to file a complaint against PG&E with the Federal Energy Regulatory Commission (FERC). The Council asserts that OCEI places an undue burden on Alameda Municipal Power (AMP) and its customers. Alameda is located on an island in the San Francisco Bay, adjacent to Oakland. AMP fears that if OCEI does not work properly, the island's two connections to the power grid will be reduced to one — putting their customers at risk of losing power for an extended period of time. AMP management said that "*nearly every attempt by AMP to engage in a meaningful dialogue with PG&E has been met with resistance, delay and, on occasion, a complete refusal to even communicate or otherwise return emails*".

7.6 Replicability and scalability potential

Replicating the approach requires an enabling regulatory framework. Indeed, PG&E has to seek approval through the Public Utilities Commission of the State of California (CPUC) for its procurement contracts.

On this point, the CPUC decision (2019c) requiring electric system reliability procurement for 2021-2023 states that all sources shall be considered toward the 3,300 MW requirement. This covers new and existing sources, preferred and conventional sources, CHP, and demand-side resources. It is interesting to note that CPUC chose to not set a specific target for certain types of resources.[39] The CPUC (2019c) states that

[39] One exception is made to the principle of parity in view of reaching climate and energy targets: new development of fossil-fuel-only resources, at sites without previous electricity generation facilities, will not be considered towards the procurement obligation. The debate about the closure of fossil-fuel plants is vivid in California. The CPUC has

"*resources with different costs and benefits may be evaluated differently, so long as similar attributes are valued similarly*." The CPUC will not prescribe the exact metrics to be used to compare different types of resources, but it will require the investor-owned utilities to conduct their solicitations in a non-discriminatory manner – treating all resources on a level playing field as long as they deliver equivalent value.

In the European Union, only network services (and companies) remain in the regulated segment; generation and supply are market-based activities. For this reason, dealing with a retiring generation asset would involve a different process. Regarding network planning, the new market design (EU, 2019/943 and EU 2019/944) now requires both TSOs and DSOs to consider demand-side resources in their network planning (for more information, see Enefirst, 2020), which should improve the planning processes.

Regarding reliability planning, decision-makers in many countries have fallen back on capacity mechanisms as a temporary measure to secure investments in capacity assets (Pató et al., 2019), despite concerns about their effectiveness.[40] Article 18 of the recast EU Regulation on the internal market for electricity (EU, 2019/943) now states that demand-side resources need to be treated equally with supply-side in capacity mechanisms.[41]

The enforcement of these provisions will be crucial to allow the contribution of demand-side resources towards reliability objectives, within or preferably outside of a capacity mechanism. Attention is required, as the acceptance of demand response and energy efficiency bids in the capacity auctions does not necessarily mean that demand resources are on an equal footing with supply (Pató et al., 2019).[42]

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extended the deadline for some plant's retirements due to reliability concerns, despite environmental concerns (CPUC, 2019c).

It is also interesting to note that a debate also took place in the Federal Energy Regulatory Commission (FERC) over the extension of CAISO's authority to contract for power generation outside of its electricity markets when the operator feels reliability may be threatened. Source: (Politico, 2019).

[40] On the issue of reliability concerns, see (Hogan, 2016).

[41] Member States with adequacy concerns must set up a plan for market reform that will eventually lead to the elimination of capacity mechanisms. This plan "should enable self-generation, energy storage, demand-side measures and energy efficiency by adopting measures to eliminate any identified regulatory distortions." The European Commission will review the implementation plans and decide whether the measures planned for market reform are sufficient. National Regulatory Authorities will report on implementation annually.

[42] In November 2018, the EU's General Court annulled the European Commission's decision to approve Great Britain's Capacity Market Mechanism, following concerns over discriminatory provisions hindering demand-response participation. For more information, see Pató et al., 2019.

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8 UPDATING DISTRIBUTION SYSTEM PLANNING RULES IN COLORADO AND NEVADA

Country/region	Colorado and Nevada (United States)
Type of E1st approach	B – In front / Investment 3 – Requiring E1st-proof assessments (Integrated distributed planning)
Energy carrier(s) targeted	Electricity
Sector(s) / energy system(s) or end uses targeted	All sectors connected to distribution grids
Implementing bodies	Colorado Public Utilities Commission (PUC) State of Nevada Public Utilities Commission (PUCN)
Decision-makers involved	Regulators Utilities
Main objective(s)	Maximise the use of distributed energy resources, including energy efficiency and demand response, and anticipate their impact on grid needs
Implementation period	Starting now or about to start

Until recently, regulators in the United States were giving little scrutiny to how the electric distribution system — which carries electricity from the transmission system to individual consumers — was planned by utilities (MADRI, 2019). The integration of distributed energy resources into the electric power system by utilities, independent power producers and energy consumers has opened the need for more regulatory oversight. Their increase provides opportunities to accelerate the energy transition. Sound network planning is required to maximise benefits for the environment and for consumers. This case study looks at the distribution system planning rules currently under examination in Colorado, and to those just adopted in Nevada, in view of discussing how the E1st principle is being enacted through the use of appropriate integrated resource planning tools. Important considerations for planning include the alignment and consistency of the different utility plans, setting a proper planning timeframe, and ensuring sufficient regulatory and stakeholder oversight over the process, based on rules which allow for a dynamic forecast of distributed energy resources and for recognising the value of non-wires alternatives.

8.1 Background

An integrated resource plan is "a utility plan for meeting forecasted annual peak and energy demand, plus some established reserve margin, through a combination of supply-side and demand-side resources over a specified future period" (Wilson and Biewald, 2013). This process used in the power sector allows the combining of resources "to provide energy services at minimum cost, including environmental and social costs" (Swisher et al., 1997). Taking into account both supply-side and demand-side resources provides an "opportunity to achieve lower overall costs than might result from considering only supply-side options" (Wilson and Biewald, 2013). This approach is in line with the definition of the E1st principle (ENEFIRST, 2020).

Today, nearly 30 U.S. states require all or some of their utilities to file an integrated resource plan with the regulator, allowing for longer-term planning and for identifying options for meeting customers' anticipated needs for electric services in a way that addresses multiple objectives (ENEFIRST, 2020). In some cases, energy efficiency is treated comparably to supply-side resources within the plan itself, while in other cases it is less integral to the process and "more heavily influenced by other political or economic considerations" (Lamont and Gerhard, 2013).

Until recently, regulators in the United States were giving little or no scrutiny to how the electric distribution system — which carries electricity from the transmission system to individual consumers — was planned by utilities (MADRI, 2019). Utilities were preparing distribution network development plans, but these plans were mostly kept internal and separate from the states' integrated resource planning efforts.

The integration of increasing amounts of distributed energy resources into the electric power system by utilities, independent power producers and energy consumers has changed the game. Distributed energy resources cover both demand resources (energy efficiency and demand response), distributed supply (photovoltaic, micro CHP systems, etc.) and storage systems. Their development, but also their untapped potential to deliver on the energy transition while maximising benefits for the environment and for consumers, has opened the need for more regulatory oversight on distribution system planning (MADRI, 2019).

This case study looks at the distribution system planning rules currently under examination in Colorado, and those just adopted in Nevada, in view of discussing how the E1st principle is being enacted through the use of appropriate integrated resource planning tools.

8.2 How has the E1st principle (or similar concept) been implemented?

In Nevada, Senate Bill 146 was approved in June 2017, revising the rules of integrated resource planning. Utilities are now required to file three-year distribution plans with the Public Utilities Commission of Nevada (PUCN) as part of their triennial integrated resource plans (Nevada, 2017).

The Public Utility Commission of Colorado (PUC) has traditionally considered all distribution system investments to be in the "ordinary course of business." Utilities have typically developed internal, five-year distribution plans, meaning that neither stakeholders nor the Commission have an opportunity to provide input to that plan (Colorado PUC, 2019). Senate Bill 19-236, signed in May 2019, directs the PUC to promulgate rules establishing the filing of Distribution System Plans by Colorado electric utilities (Colorado, 2019). Draft rules were due by March 2019. They have not been published at the time of writing.

In the U.S., the Mid-Atlantic Distributed Resources Initiative (MADRI) was established in 2004 by a number of state regulators along with the U.S. Department of Energy (DOE), U.S. Environmental Protection Agency (EPA), Federal Energy Regulatory Commission (FERC) and PJM Interconnection. It sought to identify and remedy retail and wholesale market barriers to the deployment of distributed generation, demand response, energy efficiency and energy storage in the Mid-Atlantic region.[43]

MADRI (2019) has developed guidance for regulators designing integrated distribution planning for electric utilities. For the purpose of this case study, some of MADRI's recommendations are examined below. They have been grouped into three themes to examine how the efficiency first principle can be enacted: scope of planning, governance and assessment of options.

Theme 1: Scope of planning

Geographical coverage - MADRI (2019) notes that integrated distribution planning can be implemented by one utility at a time or through a joint proceeding involving all regulated utilities. Both approaches have pros and cons: the former allows for a "deeper dive," the latter could produce a "more consistent statewide approach" to planning. In Nevada, distribution planning has been integrated into the regular resource planning process (utility by utility approach). In Colorado, rules are yet to be approved.

Consistency - MADRI (2019) recommends considering whether to align the timing and frequency of integrated distribution planning filings with other related plans, such as integrated resource plan filings, energy assurance plans, energy master plans, etc. In Nevada, the distributed plan is filed together with the resource plan of the utility, and those documents shall be consistent. In Colorado, stakeholders have been consulted (Colorado PUC, 2019) on how distribution system plans filings be coordinated with other filings with the Public Utility Commission,[44] and on whether there is a preferred sequencing of planning and reporting.[45]

Time coverage - The length of the planning horizon, the timing of plan filings, and the frequency of plan updates are also parameters to be considered. Based on practices observed to date, MADRI recommends a five- to ten-year planning horizon at a minimum, as well as frequent updates to each utility's plan to provide for the rapid pace of change in the power sector (annual updates, or two or three years between filings if this is difficult to manage). In Nevada, distributed resources plans shall be submitted every third year as part of the utility's overall resource plan. These three-year plans should take into account a forecast of net distribution system load and distributed resources over a six-year period. The utility shall file an updated plan each year. In Colorado, stakeholders have been consulted about the frequency of planning, and on whether plans should address both short-term capital investments (1-3 years) and long-term capital plans (7-10 years) (Colorado PUC, 2019).

Theme 2: Governance

Approval by the regulator - The regulator must decide whether a utility filing should be informational or subject to a regulator's approval that binds the utility to the planned course of action (MADRI, 2019).[46] In

[43] MADRI meetings were organised and facilitated by the Regulatory Assistance Project, funded through the U.S. DOE.
[44] Specifically, Electric Resource Plans (ERPs), Renewable Energy Standard (RES), annual generation and transmission facilities filings, Certificate of Public Convenience and Necessity filings, and transportation electrification applications.
[45] Whereby certain proceedings yield decisions that inform other proceedings, or proceedings occur in parallel.
[46] Even if a plan is approved, the regulator might still require the utility's actions be reasonable and prudent at the time each action is taken (MADRI, 2019).

Nevada, the regulator has to approve the plans and determine whether the plan is prudent. In Colorado, stakeholders were consulted on what principles the regulator should consider in setting criteria to govern the review and approval of distribution system plans (Colorado PUC, 2019).

Role of stakeholders - MADRI (2019) notes that stakeholder participation increases transparency and creates more confidence in the process. It recommends that at a minimum, stakeholders should have the opportunity to review and comment on a filed integrated distribution planning. In Nevada, Strategen Consulting (2018) has published an analysis of NV Energy's Integrated Resource Plan as well as an Alternative Resource Portfolio.[47] In Colorado, stakeholders have been calling to set up an integrated distribution planning process. Stakeholders have been consulted on whether they should have the opportunity to provide input into forecasting assumptions and methodology (Colorado PUC, 2019).

Theme 3: Assessment of options

Volkmann (2019) highlights the difference between the traditional distribution planning process and integrated distribution planning.

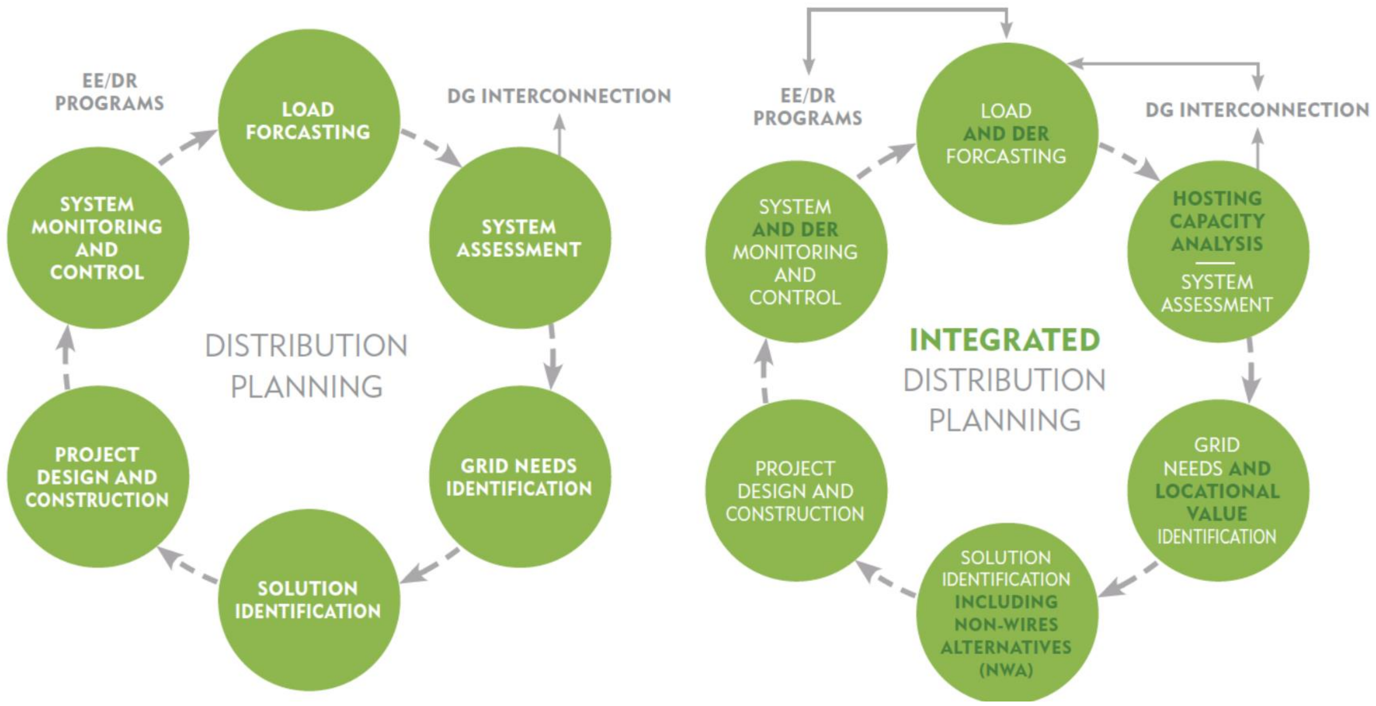

Figure 12 – Comparison between distribution planning and integrated distribution planning (Source: Volkmann, 2019)

Two parameters make a difference with regard to the implementation of the E1st principle:

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[47] The development of this Alternative Portfolio would, according to WRA, "reduce future investments in natural gas and replace those resources with increased levels of energy efficiency, renewables, and battery storage." It could "save customers over $192 million, compared to the Low Carbon portfolio selected by NVE." Source: Strategen Consulting, 2018.

Dynamic forecast of distributed energy resources - As explained by Lamont and Gerhard (2013), in traditional planning a certain amount of demand-side solutions are considered. This simply reduces the load forecast. The gap is filled by supply-side resources even if less costly demand-side savings are available. The graph above shows that integrated distribution planning requires distributed energy resources, including demand-side solutions, to be considered in a dynamic manner, meaning both as an input and an output of the model. Whenever there is an imbalance between demand and supply, both types of options shall be considered.

In Nevada, distributed resources plans shall be submitted every third year as part of the utility's overall resource plan. The regulator needs to determine that forecasts and analysis are prudently performed, and that the selection of new distributed resources is reasonable.

In Colorado, electric utilities currently take into account some forecasted distributed energy resources in their load forecasts, but the regulator notes that there may be a need to better account for the impacts of policies and goals (e.g., increasing electrification of heating and transport). Stakeholders are consulted on how utilities should incorporate load growth patterns and drivers outside of their historical experience (Colorado PUC, 2019).

The solutions/investments identified include non-wires alternatives - MADRI (2019) notes that integrated distribution planning needs to be comprehensive in terms of examining the entire grid and all the potential options for improving the grid from a reliability, resilience and cost effectiveness standpoint. Table 6 below presents the distributed resources considered in Nevada and Colorado.

Table 6 – Resources considered in distribution system planning in Nevada and Colorado

Nevada	Colorado
• Distributed generation systems • Energy efficiency • Energy storage • Electric vehicles • Demand response technologies	• Renewable electric generation • Energy efficiency measures • Energy storage systems connected to the distribution grid • Demand response measures • Microgrids
Proposed regulation of the Public Utilities Commission of Nevada. September 26, 2018.	*Colorado Senate Bill 19-236 (2019)*

In Nevada, the distributed resources plan evaluates the locational benefits and costs of distributed resources. This evaluation must be based on reductions or increases in local generation capacity needs, avoided or increased investments in distribution infrastructure, safety benefits, reliability benefits and any other savings the distributed resources provide to the electricity grid or costs to customers of the electric utility or utilities.

In Colorado, the legislation requires the regulator to develop a methodology for evaluating the costs and net benefits of using distributed energy resources as non-wires alternatives. The rules also determine a threshold for the size of a new distribution project (whether in dollars, meters or another factor), for when a utility must consider implementation or use of non-wires alternatives.[48] Stakeholders have been asked the following questions (Colorado PUC, 2019): How can distribution system planning integrate non-wires alternatives in a way that allows utility customers and distributed energy resources providers to provide incremental value to the utility system? What types of costs and benefits should be considered?

To conclude, important considerations for enacting the Efficiency First principle include the alignment and consistency of the different utility plans, setting the proper planning timeframe, and ensuring sufficient regulatory and stakeholder oversight over the process, based on rules which allow for a dynamic forecast of distributed energy resources and for recognising the value of non-wires alternatives in the assessment techniques.

8.3 Effects / impacts

In Nevada, the first distributed resources plan was submitted by the utility NV Energy in 2019. Stakeholder group Interstate Renewable Energy Council (IREC) has engaged in the regulatory proceeding to implement the new rules. According to IREC, these rules will “enable greater grid transparency and support the optimised, efficient and cost-effective deployment” of distributed energy resources.

Stakeholder negotiations led to the approval by the regulator of utility NVE’s first distribution plan. IREC and NCARE (representing WRA, Natural Resources Defense Council, Sierra Club, Southwest Energy Efficiency Project and other groups) were involved (Baldwin, 2019).

In Colorado, the rules are not in place yet.

8.4 Changes over time, if any

Rules are recent (Nevada) or yet to be adopted (Colorado).

8.5 Barriers and success factors

Volkmann (2019) lists some of the tools which should be deployed to allow integrated distribution planning. These notably include:

- Advanced Forecasting and System Modelling, which models the growth of distributed energy resource and includes a more detailed system modelling of loads and the impacts on the distribution system.
- Hosting Capacity Analysis, which helps determine how much additional distributed energy resources each distribution circuit can accommodate without requiring upgrades.

[48] Potentially including energy efficiency measures under utility programmes for new electric service to any planned new neighborhoods or housing developments.

- Disclosure of Grid Needs and Locational Value, which helps identify and communicate about opportunities for distributed energy resources and locations where their deployment can provide grid benefits.
- New solution acquisition, which allows the acquisition or sourcing of distributed energy resources from customers and third parties to provide grid services using pricing, programmes or procurement.

On this last point, it is important to note that integrated distribution planning will not ensure the deployment of energy efficiency and demand response solutions on its own. As noted by Lamont and Gerhard (2013), energy efficiency is often less costly but "practical and financial considerations" are governing the speed at which energy efficiency resources can be deployed. These include market acceptance constraints, upstream capacity for product development and know how, and allowing for the adaptation of the utility business model.

Energy efficiency policies and goals should help address these barriers and value the benefits of demand-side solutions, which should be properly recognised in cost-benefit analyses conducted by the regulators.

8.6 Replicability and scalability potential

As noted by the European Commission (2016) in its impact assessment for the revamp of electricity market rules, the regulatory framework in the EU has so far not incentivised distribution network operators to actively manage the electricity flows in their networks, nor to provide incentives to customers connected to distribution grids to use the network more efficiently. Distribution System Operators (DSO) were not provided "proper incentives for investing in innovative solutions which promote energy efficiency or demand-response." The framework also failed to "recognise the use of flexibility as an alternative to grid expansion." There have also been "fears over the impact that the deployment of distributed resources could have at system-level" (Prettico et al., 2019).

The new EU rules on electricity markets[49] should allow an increased mobilisation of distributed resources. ENEFIRST (2020) describes the relevant legal provisions:

- Distribution network development plans shall be published and submitted to the National Regulatory Authorities every two years (Article 32; EU, 2019, 2019/944).
- These plans shall identify the needed medium- and long-term flexibility services. They shall include the use of demand response, energy efficiency, energy storage facilities or other resources as an alternative to system expansion (Article 32; EU, 2019, 2019/944).
- National Regulatory Authorities may introduce performance targets in order to incentivise DSOs to raise efficiencies, including through energy efficiency, flexibility and the development of smart grids and intelligent metering systems, in their networks (Article 18; EU, 2019, 2019/943).

[49] European Union (2019). Directive (EU) 2019/944 of the European Parliament and of the Council of 5 June 2019 on common rules for the internal market for electricity and amending Directive 2012/27/EU (recast); and European Union (2019). Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity (recast).

- Regulatory frameworks shall incentivise DSOs to procure flexibility services, including congestion management, and ensure that they procure energy efficiency, demand response and distributed generation and storage "when such services cost effectively" supplant the need to upgrade capacity (Article 32; EU, 2019, 2019/944).

Some European DSOs are already implementing such a practise, as shown in the example 2 (*Social Constraint Management Zones to harvest demand flexibility*). The practise is still recent, and both DSOs and regulators will need to ensure that they have the right capacity to develop and review the distribution network development plans. The benefits of the exercise are numerous, starting with an increase in the transparency over investments in distribution networks.

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9 ASSESSING THE VALUE OF DEMAND-SIDE RESOURCES

Country/region	US
Type of E1st approach	B – In front / Investment 3 – Requiring E1st-proof assessments
Energy carrier(s) targeted	Electricity
Sector(s) / energy system(s) or end uses targeted	All end users Generation / transmission / distribution
Implementing bodies	ConEd (integrated utility)
Decision-makers involved	NY Public Service Commission
Main objective(s)	Benefit Cost Framework to assess demand-side resources
Implementation period	Ongoing since 2016

U.S. utilities are required to develop appropriate methodologies for evaluating non-wire solutions. Designing appropriate methodologies is essential for the integration of NWSs to pressing grid problems. ConEd's BCA Handbook includes many critical elements required for the assessment of demand-side resources.

9.1 Background

Non-wire solutions portfolios of distributed energy resources (DER) like solar photovoltaics, energy storage, energy efficiency and demand response often offer more cost-efficient solutions to grid capacity/congestion problems than traditional investments in networks. However, despite the various benefits associated with NWSs, several barriers hamper their widespread use (Prince et al., 2018):

- Ill-designed regulations (e.g., the lack of incentives for utilities to use these solutions).
- Utility standard procedures that neglect NWSs (e.g., internal corporate professional structure able to deal with both supply and demand issues).
- Difficulties related to the procurement of these resources.

Procurement is typically associated with consumer programmes (when consumers offer their demand response to the utility, often via aggregators), pricing mechanisms (all forms of dynamic pricing that can shift consumption away from peak periods) or public procurements. Procurement of NWSs requires a well-considered assessment methodology that considers both the technical ability of NWSs to meet grid needs and the cost-effectiveness of these solutions. As NWS includes distribution resources spanning across supply (distributed generation), network (smart network operation) and demand resources with varying associated cost and benefits, methodologies need to be developed and used that are specific to NWSs. The analyses of how demand resources are evaluated by U.S. utilities that have the most experience with employing these solutions highlights some of the challenges European distribution system operators face now as the Electricity Regulation requires them to consider these alternatives to traditional network investments.

9.2 How has the E1st principle (or similar concept) been implemented?

The New York Public Service Commission prepared a BCA framework (NY PUC, 2016) that the utilities have to consider when preparing their own BCA methodology. The framework developed is considered to be a complex but robust benefit-cost methodology encompassing most of the best practices in NWS assessment. The development of the BCA framework is best understood in the broader context of the overall Reforming Energy Vision (REV) effort of New York State by contributing to the target of consuming 70% of electricity from renewable resources by 2030.

The BCA Order must be applied to the following utility expenditure categories:

- Investments in distributed system platform (DSP) capabilities.
- Procurement of DER through competitive selection.
- Procurement of DER through tariffs.
- Energy efficiency programmes.

The fundamental principles of the NY BCA framework are:

"*1) be based on transparent assumptions and methodologies; list all benefits and costs including those that are localised and more granular;*

2) avoid combining or conflating different benefits and costs;

3) assess portfolios rather than individual measures or investments (allowing for consideration of potential synergies and economies among measures);

4) address the full lifetime of the investment while reflecting sensitivities on key assumptions; and,

5) compare benefits and costs to traditional alternatives instead of valuing them in isolation."

ConEdison developed its own BCA Handbook on these fundamentals. Alongside cost avoidance and system efficiency benefits, the BCA framework reflects the consideration of social values (externalities) quantifiably when feasible and qualitatively when not. The Public Utility Commission (PUC) hence ordered the use the Societal Cost Test (SCT) as the primary test in the framework. The role of the Utility Cost Test (UCT) and Ratepayer Impact Measure (RIM) is to assess the impact on utility cost and consumer bill from projects that pass the SCT. STC considers the cost and benefits from the wider social perspective.

Table 7 – Cost effectiveness tests

Cost test	Perspective	Key Questions Answered	Calculation Approach
SCT	**Society**	**Is the State of NY better off as a whole?**	**Compares the costs incurred to design and deliver projects, and customer costs with avoided electricity and other supply-side resource costs (e.g., generation, transmission, and natural gas); also includes the cost of externalities (e.g., carbon emissions and other net non-energy benefits)**
UCT	**Utility**	**How will utility cost be affected?**	**Compares the costs incurred to design, deliver, and manage projects by the utility with avoided electricity supply-side resource costs**
RIM	**Ratepayer**	**How will utility rates be affected?**	**Compares utility costs and utility bill reductions with avoided electricity and other supply-side resource costs**

(Source: Con Edison BCA Handbook – v2.0 (7/31/2018))

The SCT covers all of the costs and benefits defined in the PUC framework, with the exception of lost utility revenue and shareholder incentives as these are only transfers between stakeholder groups, similar to the wholesale market price impact as the price suppression is also considered a transfer from large generators to market participants (Table 8). More importantly, this test includes externalities related to pollution and resource use. While wholesale markets reflect the value of existing programmes for controlling air emissions, they do not reflect the full external value of those emissions.

For instance, avoided CO_2, SO_2 and NO_x emissions are monetised; avoided water and land use impact and the net non-energy benefits to utility or grid operation are to be assessed qualitatively. As utilities in New York do not receive incentives for decreased CO2 or other environmental impacts and the benefits related to avoided outages go to customers and not utilities, they are not included in the UCT and the RIM.

The net marginal damage cost of CO2 is based on the cost of carbon set by the Regional Greenhouse Gas Initiative (RGGI). This is a $/MWh adder based on the U.S. Environmental Protection Agency damage cost estimates.

Net Avoided SO2 and NOx includes the incremental value of avoided or added emissions. The (avoided) LBMP[50] already internalises the cost of these pollutants via the carbon cap-and-trade programmes. Hence, only those generation units <25 MW that are not covered in these programmes will be included here.

The discount rate used for comparing utility investment in resource alternatives is the weighted average cost of capital (WACC) that is 6.8% for ConEd. There is one exception to this default rate, and that is the discount for calculating the cost of carbon (CO2 emissions) where the framework requires the use of a 3% social discount rate.

[50] Avoided LBMP is avoided energy purchased at the Locational Based Marginal Price (LBMP), including all three components (i.e., energy, congestion and losses).

Table 8 – The costs and benefits in the various applied tests

	STC	UTC	RIM
Benefit	✓	✓	✓
Avoided Generation Capacity Costs	✓	✓	✓
Avoided LBMP	✓	✓	✓
Avoided Transmission Capacity Infrastructure	✓	✓	✓
Avoided Transmission Losses	✓	✓	✓
Avoided Ancillary Services	✓	✓	✓
Wholesale Market Price Impacts		✓	✓
Avoided Distribution Capacity Infrastructure	✓	✓	✓
Avoided O&M	✓	✓	✓
Avoided Distribution Losses	✓	✓	✓
Net Avoided Restoration Costs	✓	✓	✓
Net Avoided Outage Costs	✓		
Net Avoided CO2	✓		
Net Avoided SO2 and NOx	✓		
Avoided Water Impacts	✓		
Avoided Land Impacts	✓		
Net Non-Energy Benefits	✓	✓	✓
Cost			
Program Administration Costs	✓	✓	✓
Added Ancillary Service Costs		✓	✓
Incremental T&D and DSP Costs	✓	✓	✓
Participant DER Cost	✓		
Lost Utility Revenue			✓
Shareholder Incentives			✓
Net Non-Energy Costs	✓	✓	✓

(Source: Con Edison BCA Handbook – v2.0 (7/31/2018))

9.3 Effects / impacts

The New York BCA Framework and the ConEd BCA Handbook - v1.0 were developed in 2016 when ConEd already had substantial experience with public solicitations for NWSs. Having a detailed guidance increases transparency on how projects are valued. This provides incentives for potential providers, i.e., the customers of the utility to come forward with projects for the procurements announced by ConEd (current open tenders can be found here).

9.4 Changes over time, if any

The 2018 BCA Handbook Template 2.0 was developed in 2018 and reflects revisions to the 2016 filing.

9.5 Barriers and success factors

The utility Con Edison – jointly with other New York utilities – organises stakeholder involvement on a continuous basis; the wider the pool of future solution providers, the lower the resource acquisition cost is. Fundamental to the success of NWSs in New York is the state level sets ambitious sustainable targets and the regulation of the utilities incentivise them to use these alternative approaches to traditional network investment (see example 6 *Decoupling utility sales and revenues*).

9.6 Replicability and scalability potential

Even though New York is often quoted as a pioneer in employing NWSs, many other U.S. states are already in the process of eliminating the barriers, including developing future-proof evaluation methodologies (Prince et al., 2018). European network companies have to deal with the NWSs in the near future as the Electricity Market Directive (2019/944/EU) calls for national regulators to require DSOs and TSOs to consider alternative solutions to network investment and, because of the least-cost principle, to substitute them whenever is it cost-efficient. More specifically (Art 32):

- Distribution network development plans shall be published and submitted to the National Regulatory Authorities every two years.
- These plans shall identify the needed medium- and long-term flexibility services that must include the use of demand response, energy efficiency, energy storage facilities or other resources as an alternative to system expansion.

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10 WATER HEATERS AS MULTIPLE GRID RESOURCES

Country/region	Hawaii (U.S.)
Type of E1st approach	C – Behind / General 1 – Allowing E1st
Energy carrier(s) targeted	Electricity
Sector(s) / energy system(s) or end uses targeted	Residential and distribution
Implementing bodies	HECO (utility) and Shifted Energy (third-party service provider)
Decision-makers involved	Hawaii Public Utilities Commission (energy regulator)
Main objective(s)	2.5 MW demand response and other grid services provided by Grid Interactive Water Heaters (GIWHs) to a Hawaiian utility
Implementation period	2018-

Tanks equipped with electric resistance water heaters are widely used domestic appliances. Apart from supplying hot water, they can offer various power system benefits as well. Traditionally, they are used as thermal storage devices by delinking the time of demand for and generation of hot water: heating up water in the tank in periods of low overall power demand (e.g., at night). However, with a minor upgrade, these appliances can provide further grid services as well as save money for consumers. The recent programme initiated in Hawaii is a prime example of stacking benefits from water heaters as demand-side resources and a showcase of how a third-party service provider startup can come up with solutions for efficient grid operation.

10.1 Background

Electric resistance water heaters are important demand response resources and are expected to remain so. Smart water heating is estimated to provide more cost-effective flexibility than dynamic tariffs in the U.S. in 2030 (Figure 13).

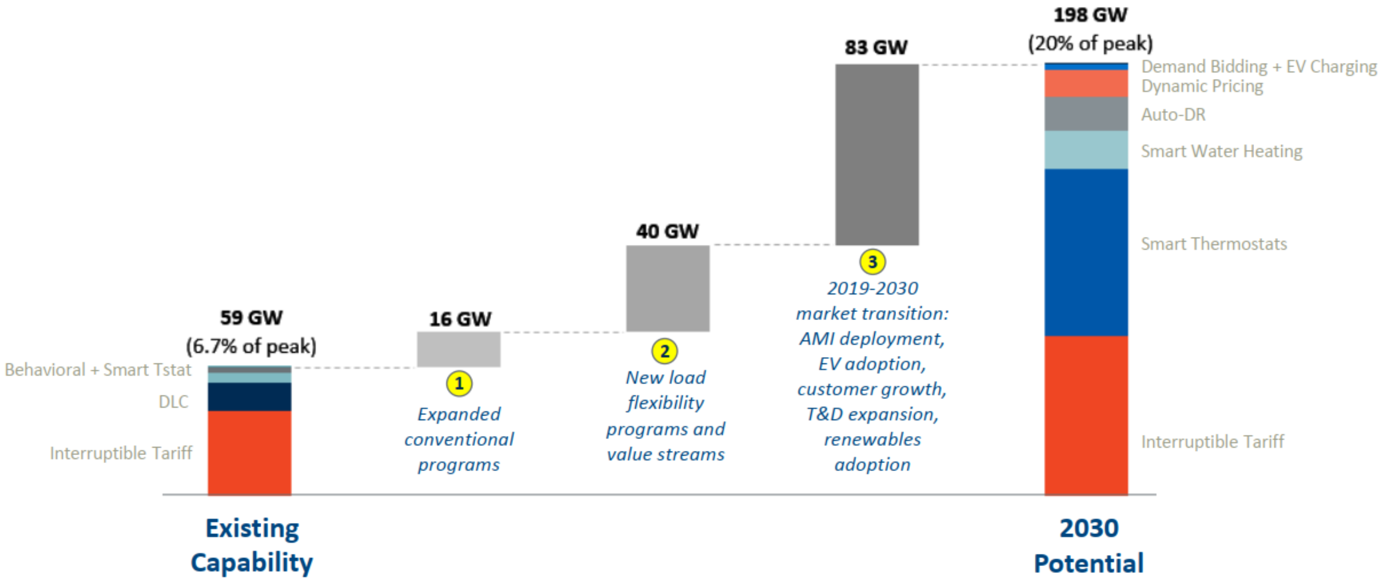

Figure 13 – Cost effective load flexibility potential in the U.S. (Source: Hledik et al., 2019)

Water heaters are traditionally used in many countries to shift demand from peak periods to periods of abundant supply. This is increasingly important because of the increasing share of weather-dependent renewables in the supply. The thermal storage property of water heaters makes them very similar to batteries. Technically, they are directly controlled by utilities that turn them off as needed in a peak period without the consumers experiencing any disturbances in hot water supply. The associated system benefits are that of avoided generation, avoided transmission and distribution network reinforcement, and the curtailment of wholesale prices in these hours.

The magnitude of this relatively untapped resource is significant: it is the third single largest source of residential electricity consumption (9%), behind space cooling and lighting, in more than 40% of U.S. households (Hledik et al., 2016).

Water heaters, if equipped with modern control devices, can participate in frequency regulation and grid balancing services for the power system as well (Figure 14). These grid interactive water heaters can be controlled with near instantaneous response from the operator, and these additional benefits are increasingly valuable in markets with rapid fluctuations in supply due to the large share of renewable sources.

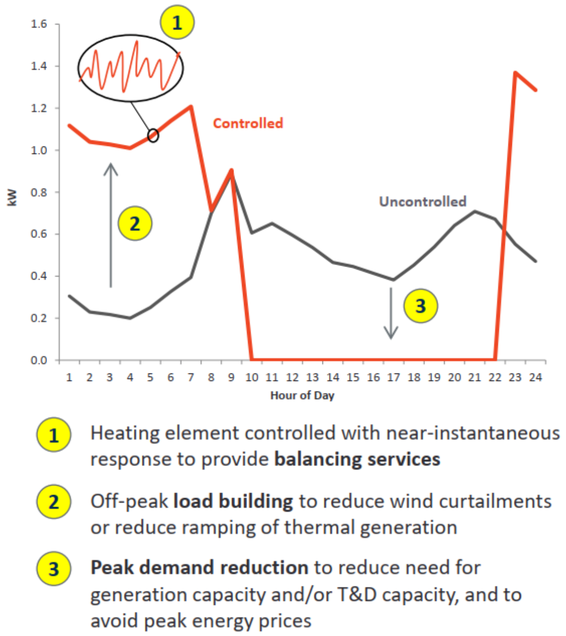

Figure 14 – Water heating load profile

(Source: Hledik et al., 2016)

If an 80-gallon tank electric resistance water heater is able to interact with the grid beyond simply shaving peak and building load within the day, then the net benefits (considering the extra cost of upgrading the heater) triples, mainly due to the benefit provided for frequency control (Figure 15). This, however, can only materialise if market rules allow demand-side resources to participate in ancillary services markets.

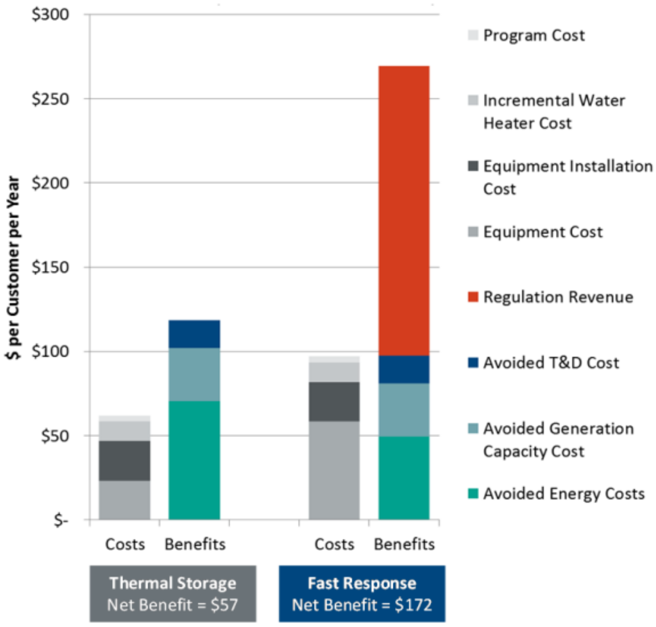

Figure 15 – Costs and benefits for 80-gallon tank

(Source: Hledik et al., 2016)

In sum, electric water heaters can provide various demand response services. In the taxonomy developed by the Lawrence Berkeley National Lab and increasingly used to differentiate between DR services, they do not only “Shift” but also “Shimmy” as well (Alstone et al., 2017): not only to move energy consumption from peak times to times of day when there is a surplus of renewable generation, but also to use loads to dynamically adjust system demand to alleviate short-run ramps and disturbances at timescales ranging from seconds up to an hour.[51]

10.2 How has the E1st principle (or similar concept) been implemented?

Across 53 U.S. utilities, electric water heater DR programmes have a total enrolled capacity of 585.6 MW, representing 2% of the total enrolled DR capacity, and 11 states are running pilots on grid interactive water heaters (SEPA, 2019).[52]

Hawaii is a nice illustration of how a traditional utility DR programme can be upscaled to provide a much larger rollout and more services with the involvement of third-party actors. Hawaiian Electric (the utility) has relied on electric water heaters as demand response devices for years. Its EnergyScout programme uses a one-way paging network to control about 34,000 water heaters, which deliver approximately 10 MW of controllable peak demand.[53] The installed device turns off the water heaters during system peak usage, typically for no more than one hour at a time.

As a response to the request of the Hawaii Public Utilities Commission, Hawaiian Electric (HECO) launched its Grid Services Purchase Agreement in 2018 to competitively procure approximately 16 MW of capacity. This is the framework in which Shifted Energy — partnering with Open Access Technology International (OATI) – committed to deliver 2.5 MW of grid-interactive water heating.

OATI is a Minnesota-based smart-grid solution provider that was awarded the 2018 GSPA contract to deliver aggregated capacity from a combination of residential, commercial and industrial customer-sited assets, including the 2.5 MW of GIWH from Shifted Energy. OATI aggregates these resources to provide capacity and fast frequency response services to Hawaiian Electric.

Shifted Energy – based on its troublesome experience with installing tank-mounted controllers that impacted appliance warranties and troubleshooting controller internet connections – developed a technology that would allow GIWH to be deployed at large enough scale to have a real grid impact. The system is made of the following elements:[54]

- Off-tank controller (“Tempo”) that requires a maximum of 20 minutes to install anywhere on the electric line between the breaker panel and the water heater; no sensors touch the tank (does not affect warranties) and no plumbing.

[51] This analytic framework groups DR services into four core categories: Shape, Shift, Shed and Shimmy.
[52] Arizona, California, Florida, Georgia, Hawaii, Minnesota, North Carolina, Oregon, South Dakota, Washington and Wisconsin.
[53] https://sepapower.org/knowledge/two-birds-one-water-heater-how-shifted-energy-and-hawaiian-electric-are-helping-hawaii-meet-its-clean-energy-goals/
[54] http://www.shiftedenergy.com/technology/

- Integrated cellular chip and antenna operate independently of the customer internet network and include end-to-end cyber security.
- A software-as-a-service platform ("Grid Maestro") that monitors, analyses 5-minute, revenue-grade data and optimises smart water heaters through machine learning.[55] Grid Maestro aggregates each heater's forecasts and load shift potential into a virtual power plant of grid interactive water heaters (Figure 16). Automated reporting and integrated ticketing simplify performance measurement and verification.

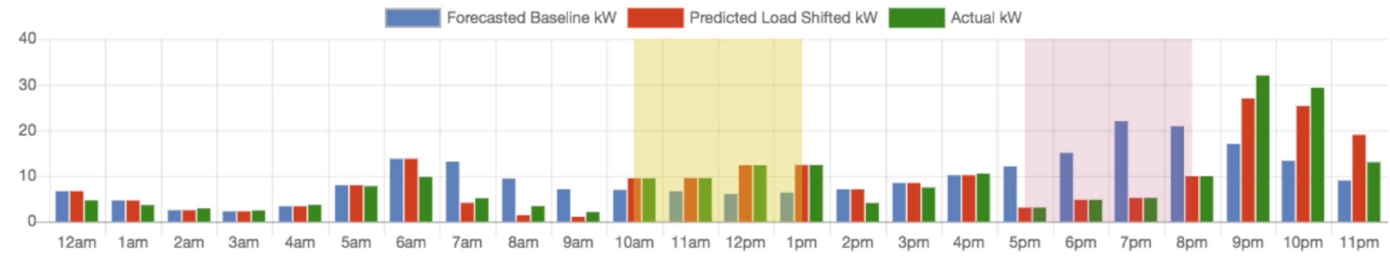

Figure 16 – Scheduling load shifts
(Source: http://www.shiftedenergy.com/technololgy/gridmaestro/)

Heaters provide the following grid services:

- Multi-hour load shifts by storing energy during periods of high renewable generation and reducing consumption during peak demand. In Hawaii, peak demand time (5–9 PM on weekdays) is a time when the grid is strained and when the energy with the highest emissions (oil) is being used.
- Frequency and voltage regulation: 12-cycle or less response time to frequency or voltage deviations, as well as randomised return-to-load.
- Emergency DR: Full fleet shut down to quickly shed maximum kW.

Heaters offer several benefits to the participating GIWH users:

- Optimises onsite PV self-consumption: coordinating GIWHs as thermal storages to optimise grid-injected and grid-supplied power exchange for prosumers.
- Automatically shifts load for off-peak if the consumer is enrolled in ToU and real-time pricing tariffs.
- Fault detection and alert.

The off-tank controller device is free for the participants; in return for allowing their water heaters to support the grid, they receive a monthly bill credit between $3 and $5 over the first 5 years.

10.3 Effects / impacts

As the agreement between the utility and the service provider was only signed recently (fall 2019), there is no information available about the programme's performance yet.

[55] When a new water heater is added, Grid Maestro begins monitoring that heater's energy consumption patterns. After about two weeks, the system's advanced machine learning algorithms generate highly accurate forecasts of future consumption at 15-minute intervals for four days in advance. Grid Maestro uses these forecasts to estimate how much electricity consumption can be shifted from one time of day to another without impacting consumer access to hot water.

10.4 Changes over time, if any

As this is a new programme, no change has been proposed yet.

10.5 Barriers and success factors

The only barrier that has been identified prior to the programme has been turned into a success factor of the Shifted Energy approach: the use of a control device that can be installed very quickly without touching the tank. The drive behind the utility opening a competitive tender to procure grid services that are becoming increasingly valuable with high renewable penetration is motivated by the wider policy goal that Hawaii set in 2015 to reach 100% renewable use by 2045. This is coupled with the fact that Hawaii, like many islands, is largely powered by petroleum-based generators, which makes the cost of electricity very high and thus attracts the attention of cleantech startups. Shifted Energy has been involved with solar panel and battery deployment for years and already had strong community experience with Hawaiian residents.

10.6 Replicability and scalability potential

It is difficult to see why this solution could not be replicated in other regions and countries. There are 600 million electric water heaters worldwide, and the expected growth in emerging markets (e.g., China and India) offers an enormous networked grid resource.[56] The need for increased power system flexibility and hence frequency regulation requires the involvement of demand-side resources that are cheap and abundant and can be aggregated at low cost. Water heaters are in place in many households and further electrification and the potential phase-out of gas heat supply at the distribution level will increase the penetration of electric water heaters in Europe. The future share of tank-equipped water heaters (versus tankless/on-demand heaters) is yet to be seen, however. There is an option to move beyond considering them simply as power thermal storages and make them to provide further valuable grid benefits at low cost. The regulatory environment should be supportive to third-party aggregators and solution providers in general, and markets should be designed to reflect the real value of flexibility.

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[56] https://sepapower.org/knowledge/two-birds-one-water-heater-how-shifted-energy-and-hawaiian-electric-are-helping-hawaii-meet-its-clean-energy-goals/

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11 BUILDING LOGBOOK – WONINGPAS: EXPLOITING EFFICIENCY POTENTIALS IN BUILDINGS THROUGH A DIGITAL BUILDING FILE

Country/region	Flanders, Belgium
Type of E1st approach	C – Behind / General 3 – Requiring E1st-proof assessments
Energy carrier(s) targeted	Electricity / natural gas / district heating / others – any which are connected to the building
Sector(s) / energy system(s) or end uses targeted	Residential Heating, lighting, electricity services
Implementing bodies	Flemish Energy Agency (VEA)
Decision-makers involved	Vlaams Energieagentschap/Flemish Energy Agency (VEW) and OVAM (Public Waste Agency of Flanders)
Main objective(s)	Increasing the renovation rate, increasing knowledge through collection of information on a specific building's renovation history and future, reducing the energy demand in buildings.
Implementation period	Ongoing since 2018

A digital building logbook is a new concept that has gained some attention in the EU[57] and in several Member States, such as Belgium. A digital building logbook is typically described as a digital repository where all the information related to the building (including ownership, building design, materials used, structures, installations, systems, adaptations, investment, operational and maintenance costs, health and safety, performance indicators, certifications) are compiled and updated when changes occur. Compiling and streamlining the use of data and making it accessible to the public in an anonymised way could influence the effectiveness of policies, simplify administrative procedures and contribute to a stronger link between the building's energy performance and its value.

The most advanced building logbook in the EU as of early 2020 is the Dutch Woningpas, which is a building-specific datafile. The data can be accessed by the building owner and by individuals who have been granted access by him. The Dutch logbook features energy performance, renovation advice, the housing quality (such as stability, humidity, safety) and data on the environment. The Woningpas makes it possible to track the evolution of each individual building. The first version of the instrument was launched in 2018 (iBRoad project, 2018a).

[57] The European Commission commissioned a study in 2020 on digital building logbooks delegated by Executive Agency for Small- and Medium-sized Enterprises (EASME). Results from this could feed into the upcoming renovation wave initiative of the EU.

11.1 Background

The Flemish Energy Agency (VEA), through a participatory process with a wide network of Flemish stakeholders adopted and implemented the Renovation Pact (2014-2018), designed to lead to a thorough improvement of the energy performance of the region's building stock. It established that the existing building stock in 2050 should become as energy efficient as the current minimum requirements for new buildings (E60).

Two of the main measures of the Renovation Pact were the support of the Woningpas (the building logbook) and the EPC+ (a more user-friendly version of Energy Performance Certificate EPC), including a clear overview of measures, ordered by priority. The two instruments are to provide building owners with useful, easy-to-understand information and long-term guidance. Through these instruments, the public authorities in Flanders also intend to contribute to the region's long-term objectives.

11.2 How has the E1st principle (or similar concept) been implemented?

By giving a detailed overview of the current energy performance level and a registry of the efficiency measures undertaken so far, combined with a roadmap for improving energy performance, the Efficiency First principle is applied. In line with the Dutch long-term strategy, the building logbook puts efficiency measures before renewable energy measures. It lists the measures that are necessary to reduce the overall energy demand before increasing the energy supply capacity, for example when installing a heat pump, to make sure that it is not over dimensioned. The building logbook also gives information on the cost of different measures, thereby helping the owner to take costs alongside other factors into account.

11.3 Effects / impacts

As this is a fairly new tool, it is not possible to observe any effects/impacts yet. So far, the Woningpas has not been taken up in a large enough scale to show results.

11.4 Changes over time, if any

The building logbook is a novel instrument, introduced in Flanders in 2018; therefore, the related legislation has not been changed yet. The Woningpas is closely linked to the EPC, which includes some elements of the Woningpas. Since January 2019, EPCs in Flanders list recommendations for refurbishment in line with the regional long-term decarbonisation objective. Furthermore, the logbook includes recommendations for further actions to be improved during a whole-building renovation (airtightness, ventilation etc.) and technical information to avoid lock-in effects. In the future, other building aspects such as durability, water, installations and building permits will be included.

11.5 Barriers and success factors

Logbooks have been recognised – and developed in some countries — as a way to inform and engage building owners and possibly even decision-makers and maximise the value of EPC data for them during their renovation process.

Building logbooks can help to not only trigger renovation but can also help in a step-by-step approach which leads to deeper renovations overall if the information is clear and precise and there is available data which underpins the suggested approach. Combined with other measures, like minimum energy performance requirements and trigger points to prioritise the renovation of the worst-performing buildings, the impact can be even greater. This, in turn, can lead to an indirect implementation of the Energy Efficiency First principle. The main concept behind this is that renovation measures are more cost-effective on an individual scale as well as on a macroeconomic level than, for example, covering all energy needs through renewable energies. The latter would involve too many resources for decentralised energy production (or unsustainable import of renewable energy) and therefore is not the most cost-effective and efficient solution. In order to look at the effects more in detail and give a sound assessment the concept needs to be implemented for a longer time period and closely monitored.

The key barrier or success factor for E1st will be if the Woningpas or other building logbooks ensure that renovation recommendations are implemented before the switch to renewable systems, and how this will happen. The success factor of the building logbook could be identified as giving the homeowners the full information on their buildings and how to improve them putting Efficiency First.

11.6 Replicability and scalability potential

There are other examples of the building renovation passport in Germany ("individueller Sanierungsfahrplan") and France ("EFFICeat) but Flanders with its Woningpass is so far the front runner, as this concept is much more elaborate and involves more information than the others. The European Commission has conducted a feasibility study on implementing building logbooks across Europe and it is expected that more countries will follow the Dutch example in the future if it proves to be useful for increasing the renovation rate and depth — especially if EU legislation proposes its further implementation and formally introduces it as a tool.

Flanders (Belgium), Portugal and regional administrative entities (departments) in France have developed digital registries which could be described as building logbooks, though less detailed than the Flemish Woningpas. Denmark and Ireland have very advanced EPC registries, with innovative aspects that mirror a digital building logbook.

11.7 Sources and references

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12 OPTIMISING BUILDING ENERGY DEMAND BY PASSIVE-LEVEL BUILDING CODE

Country/region	Brussels Capital Region, Belgium
Type of E1st approach	C – Behind / General 3 – Requiring E1st
Energy carrier(s) targeted	Electricity / natural gas / district heating / others
Sector(s) / energy system(s) or end uses targeted	Residential, public and commercial buildings Energy consumption: heating and cooling, lighting and electricity
Implementing bodies	Regional administration Brussels Environment (legal name IBGE-BIM)
Decision-makers involved	Regional government of Brussels Capital Region, construction industry and other representative bodies
Main objective(s)	Compliance with EPBD, reduction of CO2 emissions (reaching 80% savings in 2050), improvement of indoor air quality
Implementation period	Ongoing since 2015

Starting off as the worst region in Europe regarding the energy performance of its building stock, Brussels Capital Region used the obligations of the Energy Performance of Buildings Directive (EPBD) as an opportunity to significantly improve the energy, air and climate performance of its buildings. The regional government adopted its first energy efficiency standards in 2002, followed by a complex set of measures and large-scale stakeholder discussions and pilot projects, until it introduced stringent energy performance requirements for buildings in 2015, and tightened them since. In just a little more than 10 years, the region became an example around the globe for rapid energy transition of the building sector, prioritising efficiency and using the passive house level as the building standard. During this time, the market developed both the requirements and the solutions.

Slashing energy consumption was first motivated by a concern over high unit consumption of energy and low indoor air quality in Brussels, as well as its building stock being amongst the most energy wasteful in Europe. The stringency and coverage of the so called "passive house law" (or Energy Performance of Buildings (PEB) Regulation) in 2015 has been further strengthened and led Brussels to lead by example in building energy regulation.

12.1 Background

The Brussels Capital Region, a region of Belgium comprising 19 municipalities, one of which is the City of Brussels, became the first region in the world to adopt and implement mandatory energy efficiency building codes at the level of passive house standards. The introduction of the strict building standards was preceded by a package of voluntary and mandatory policy measures between 2002 and 2014. Key pieces of the policy package were the first thermal requirements in 2002 (K55), which required minimum insulation of new buildings across Belgium from 2002 (IEA, 2017), followed by the competitive Exemplary Buildings programme, or BatEx, from 2007 – 2013, and the Air-Climate-Energy Code (known as COBRACE) in 2013. Other measures were also instrumental in increasing the effectiveness of the building standards. Information instruments, such as the strengthening of the energy performance certificates (EPC), guidelines for home owners, collection of best practice examples, an office of advisors and facilitators, as well as supporting the industry by networking, trainings, the set-up of a one-stop shop, and financial instruments such as green loans have been and are still available today. The package of measures has ensured that the rationalisation of energy demand has been treated equally and even given priority over low-carbon energy source solutions.

In 2006, a few public buildings were renovated to passive house level in order to serve as demonstration sites. One of the critical components of the overall policy package was the Exemplary Buildings programme, BatEx. The BatEx programme targeted public, commercial and residential buildings through providing financial support for very low-energy construction and renovation projects. Leading by example and providing robust technical support and workforce development to the building sector, they won over the concerns of industry and sparked the development of a domestic manufacturing industry creating hundreds of new jobs in the process. The programme ignited market forces to prepare both the demand and the supply sides of the construction and renovation markets.

On 2 May 2013, the Brussels Capital Region adopted its Air-Climate-Energy Code (known as COBRACE 90). It served as a legal basis for its Integrated Air-Climate-Energy Plan, which was adopted on 2 June 2016. The "passive house law" (officially called the PEB Regulation) was agreed on in 2011, requiring this as the standard for all new construction as of 2015 and most renovation from 2017, and was further revised in 2019 (Brussels Environment, 2020a).

12.2 How has the E1st principle (or similar concept) been implemented?

The Efficiency First principle became embedded in the building code of Brussels through the requirement for passive design. The first thermal regulations (K55) in 2002 already set out insulation requirements. The passive house law foresees the drastic reduction of energy demand, supplying the remaining demand from renewable sources. In an urban setting, the selection and amount of renewable capacity is limited, prioritising energy efficiency.

The competitive BatEx programme resulted in projects which could provide passive solutions at standard costs, while it also catalysed the market and showed that close-to-passive-house energy performance could be achieved with a zero or minor cost premium. The energy performance of subsidised buildings was not predefined, only capped, and the market was allowed to define it on a competitive basis. The programme led to a demand and supply of close-to-passive-house level buildings, and kick-started over 3000 passive houses beyond the subsidised projects as of 2018 (van Daalen and Petersen, 2018).

12.3 Effects / impacts

The building code and its accompanying policies have contributed to a significant improvement in the energy intensity of Brussels' building sector. Between 2007 and 2013, six calls for proposals within BatEx were announced, resulting in 243 energy performance projects representing more than 621,000 m^2 of passive buildings including homes, offices, schools, hospitals and social housing (EnEffect, 2014). Beyond the subsidised projects, Brussels in 2019 had ca. 3000 passive buildings.

The total energy consumption of the building stock was almost 10,000 GWh with climate correction at the time the first measures were implemented in 2002, of which around 8500 GWh was used for combustible fuels and around 1400 GWh for electricity. With the improvement of the energy performance of new buildings, then also of renovated buildings, as well as the accompanying energy transition of home appliances, total energy consumption was a little over 7400 GWh, around 6000 GWh for combustible fuels and 1350 GWh for electricity respectively in 2017 (Brussels Environment, 2020b).

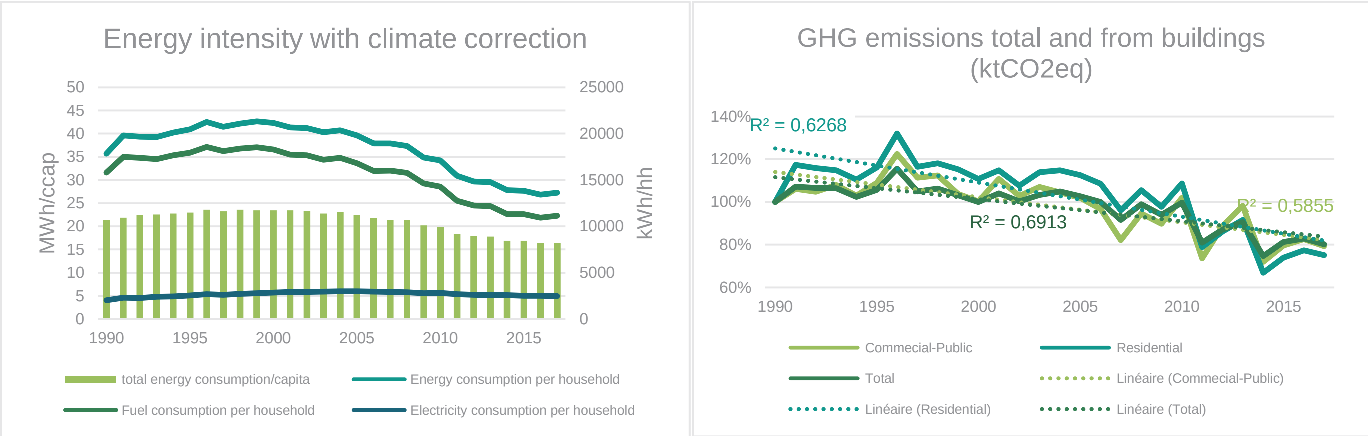

Figure 17 – The energy and climate impact of the PEB Regulation and related policy package

12.4 Changes over time, if any

The Brussels regional government first adopted energy efficiency standards in 2002, jump-starting policy discussions about climate change, energy and buildings. The standard was drastically strengthened to close-to-passive-level in 2015, based on the experiences of the policy package linked to the BatEx programme. The so-called PEB Regulation was adopted in 2011, and was set as the standard for all new construction as of 2015. The standard was extended to renovations beginning in 2017, and new requirements and calculation methods were introduced in 2017 and again in 2019 (Brussels Environment, 2020a).

12.5 Barriers and success factors

The “passive house law” (i.e. the PEB Regulation) was adopted in 2011, and introduced from 2015, with regular updates to its stringency and coverage.

Success factors:

- Despite resistance in the beginning, due to the participatory process both the tenants and the industry were well-informed, well-prepared and contributed to the formulation of the law. This has led to a system of world-renowned building policies.

- The preceding BatEx programme was led by market actors and was always at the level of market preparedness. The industry could develop along with the programme in a competitive environment, driven by market forces.
- The financial support of the programme was instrumental in overcoming the preparatory phase costs.
- Piloting passive design in selected public buildings before 2007 was a test phase for the whole set of measures.
- Skill development, trainings and certifications could improve trust and could develop the supply of professionals and professional solutions.

Barriers:

- Compliance levels were criticised in the beginning.
- Since Brussels has special buildings, such as historic buildings and tower buildings, these need specific attention and targeted legal, informational and institutional provisions.
- Participatory regulation requires additional efforts from decision-makers but pays off.

12.6 Replicability and scalability potential

The example of the stringent building standard is often referred to as exemplary and other cities and regions learn from the successes, as well as from the barriers. In particular, New York City has followed the pathways of Brussels in order to contribute to the overall city target of an 80% reduction of carbon emissions by 2050 (Yancey et al., 2016).

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13 DEFERRING T&D (TRANSMISSION & DISTRIBUTION) INFRASTRUCTURE INVESTMENTS THROUGH LOCAL END-USE EFFICIENCY MEASURES

Country/region	United States: California
Type of E1st approach	D –Behind / Investment 1 – Allowing E1st
Energy carrier(s) targeted	Electricity
Sector(s) / energy system(s) or end uses targeted	Residential / Tertiary sectors Transmission / distribution
Implementing bodies	Pacific Gas and Electric (PG&E)
Decision-makers involved	Utility, end consumers
Main objective(s)	Defer T&D infrastructure upgrades though geographically-targeted end-use efficiency measures.
Implementation period	1991-1993, 2013 - ongoing

Transmission and distribution system operators are subject to ongoing investment needs into their capital assets. In the U.S., several electricity and natural gas utilities have made successful use of locally targeted energy efficiency programmes to defer some of these investments in specific areas for a period of time (Neme and Grevatt, 2015). These projects highlight how the trade-off between demand-side resources and energy infrastructure can be practically solved, with benefits accruing to both the utility and its customers. This example discusses such activities of the Californian utility Pacific Gas and Electric (PG&E). Similar activities are or have been pursued in the states of New York, Vermont and Oregon.

13.1 Background

Pacific Gas and Electric is a regulated electric and natural gas utility serving Northern and Central California and currently supplying approximately 16 million customers in its service area (PG&E, 2020). Beginning in the early 1990s, fast-growing power demand in the suburban Delta area outside the city of San Francisco was causing a number of the company's transmission and distribution infrastructures to rapidly approach their peak capacity.[58] Facing capital expenditures of $112.3 million for the construction of a new substation and auxiliary equipment, the company began to evaluate if locally-targeted, cost-effective and reliable energy efficiency measures can reduce the need for these infrastructures and minimise the total cost of serving the Delta area (Orans et al., 1994). Based on these considerations, in July 1991, PG&E

[58] More specifically, in 1990, peak demand in the Delta area was approximately 90 MW, while the existing distribution system could serve 120 MW. PG&E anticipated about 1,200 new homes and 200 new firms added to the service area per year, corresponding to an annual load increase of 7.7 MW (Orans et al., 1994).

launched the Model Energy Communities programme (MEC) – also referred to as the Delta Project – which today is one of the most widely publicised early projects for active deferral of T&D investments (Neme and Sedano, 2012).

13.2 How has the E1st principle (or similar concept) been implemented?

One of the first steps taken by PG&E to implement the Delta Project was to involve the local community. A local citizen advisory committee was established for the project, made up of 6-12 community leaders. The purpose of the committee was to act as a sounding board for the initial programme design and possible revisions. Subsequently, potential customers for the implementation of energy efficiency measures were contacted, including details on economic and technical benefits for the customers (IEEC, 2009).

In terms of actual project implementation, PG&E designed several energy efficiency programmes for different customer groups. Given the fact that peak demand was driven primarily by residential customers who turned on their air conditioners when they arrived home after work, the largest portion of the project's savings was projected to come from residential homes. Measures included the following (IEEC, 2009; Kinert and Engel, 1992; Neme and Sedano, 2012):

- During an initial site visit, participating homes would receive free installation of low-cost efficiency measures (e.g., CFLs, low flow showerheads, water heater blankets).
- Homes could then be scheduled for follow-up work with major measures (e.g., duct sealing, air sealing, insulation, sun screening).
- Other minor programme components included commercial retrofits (e.g., retrofits for lighting, HVAC, and motors), and residential/commercial new construction (e.g., reduce cooling requirements).

Overall, 3,648 customers participated in the low-cost efficiency measures, and 2,297 customers received major measures. In addition, a total of 363 commercial retrofits were performed, and there were 318 participants in the new construction component. On average, PG&E paid 80% of direct installation project costs for the commercial programmes; in the residential sector, a complex matrix was used to calculate customer incentives (IEEC, 2009; Neme and Sedano, 2012).

Upon completing work for each participating customer, data was entered into a comprehensive database run by engineering consultants, followed by data reviews and random inspections in order to track achievable and actual programme savings. Overall, the Delta Project was completed in March 1993. In contrast to similar energy efficiency programmes during that time, it was unique in the way that it 1) considered the peak capacity constraints of a specific distribution planning area and the associated proposed substation construction; 2) expanded the energy efficiency measures to include all major market segments in the planning area (including residential and commercial retrofits as well as new construction); and 3) closely evaluated the programme process and impact relative to the local area peak demand (IEEC, 2009).

13.3 Effects / impacts

Locally targeted energy efficiency measures are of particular relevance to transmission and distribution systems that are likely to reach their peak capacity. Since T&D systems can experience peak demand at different times, the extent to which an energy efficiency programme can help defer investments in T&D infrastructures essentially depends on the hour and season of peak and the hourly and seasonal profile of the programme's savings (Neme and Grevatt, 2015).[59] Accordingly, well-designed, location-specific energy efficiency programmes can be used to significantly reduce the costs associated with upgrades in T&D infrastructures, saving money for both energy companies and customers participating in the programme (Bayer, 2015).

With regard to the Delta Project, the measures implemented are estimated to have reduced investment in local T&D infrastructures from $112.3 million to $74.4 million over a 30-year period, i.e., a 32% decrease. From a total resource cost perspective, the programme resulted in $35 million in savings (Kinert and Engel, 1992). In terms of T&D capacities, the project produced 2.3 MW of peak demand savings while also reducing annual energy consumption by 4,322 MWh (IEEC, 2009; Neme and Sedano, 2012). The savings achieved succeeded in deferring the need for the new substation and other auxiliary equipment for at least two years (Neme and Grevatt, 2015).

Overall, the cost-effectiveness of locally-targeted end-use efficiency programmes and other non-wires resources will unquestionably be project-specific. However, the experience from PG&E and similar projects implemented in the states of Vermont, New York and Oregon highlight that efficiency resources can be a valuable replacement or complement to traditional "poles and wires" alternatives in T&D system planning (Neme and Grevatt, 2015).

13.4 Changes over time, if any

Despite having been a successful pioneer of T&D infrastructure deferral in the early 1990s, PG&E did not carry out any other projects similar to the Delta Project until recently. In 2013, the company started evaluating specific capacity expansion projects at distribution substation level that required attention due to load growth and that could potentially be deferred. Starting from a list of 150 distribution capacity expansion projects within the PG&E service area that would need to be addressed in the next five years absent any action to defer them, the company ultimately selected four projects for which to deploy non-wires alternatives for the years 2014-2015. Similar to the initial Delta Project, measures were targeted for residential customers, this time focusing on HVAC equipment, pool pumps and demand response programmes for air conditioners (Grueneich, 2015; Neme and Grevatt, 2015).

13.5 Barriers and success factors

The Delta Project case certainly highlights the effectiveness of using geographically-targeted DSM measures to defer T&D system upgrades. However, throughout its implementation, PG&E was facing a very narrow timeframe. Planned and launched within six months, difficulties arose with regard to implementing management control mechanisms, quality assurance and budget tracking. Based on this, PG&E recommends selecting a targeted T&D area where the window of opportunity (i.e., capital investment

[59] Note that, besides peak loads, T&D system investments are driven by more factors, including the replacement of aging infrastructure and the need to connect new generation – particularly in the context of ongoing deployment of remotely located renewable generators. Energy efficiency programmes can hardly defer any investments related to these two factors (Neme and Grevatt, 2015).

point) is approximately three to four years out in time. Similarly, it is important to focus programme design on measures that are well-developed, commercially viable, readily available in terms of timing and quantity, and priced reasonably to enable straightforward implementation (IEEC, 2009).

In terms of success factors, two elements can be highlighted. First, the company later enhanced its management structure through the formation of an interdisciplinary working group covering all relevant functional areas (e.g., energy efficiency and demand management, distribution engineering, substation planning, electric operations). The company's experience indicates that such cross-disciplinary communication is critical to develop confidence necessary for energy efficiency programme implementers and T&D system engineers to work together effectively. Second, PG&E makes increasing use of data-driven tools, including geographically-specific potential models to assess the economics of energy efficiency for cost-effective deferral or capital expenditures required to meet growing customer demand. This has been shown to enable more sophisticated strategies for geographically-targeted efficiency programmes (Neme and Grevatt, 2015).

13.6 Replicability and scalability potential

An important issue is the applicability of the approach beyond electrical transmission and distribution systems. In principle, the experiences from the electricity sector in using demand-side resources to defer T&D upgrades are just as applicable to natural gas T&D infrastructure investments, with both sectors exhibiting similar characteristics (Bayer, 2015; Neme and Grevatt, 2015). However, according to Neme and Grevatt (2015), the practice of *active* deferral – i.e., intentionally designed and geographically-targeted energy programmes to defer specific T&D projects – has either not been widely studied or not been widely publicised with regard to the natural gas sector.

An example worth noting is Vermont Gas Systems, a natural gas utility with about 50,000 residential and commercial customers in the U.S. state of Vermont. The company routinely includes the impacts of its efficiency programmes in its integrated resource planning. As noted in its 2017 integrated resource plan (Vermont Gas Systems, 2017), energy efficiency programmes are projected to not only reduce gas purchases, but also contribute to delayed transmission investment and produce enough peak day savings to delay implementation of at least one transmission system looping project by one year (Neme and Grevatt, 2015; Vermont Gas Systems, 2017).[60]

In the EU context, the Internal Gas Market Directive (2009/73/EC) provides opportunities for the introduction of targeted demand side measures in T&D systems planning. For instance, the Directive already includes the possibility for MS to introduce a public service obligation on natural gas undertakings relating to, among other things, energy efficiency. A public service obligation could come in the form of a least-cost investment requirement that requires the consideration of supply- and demand-side resources anytime an expansion of existing infrastructure is considered (Bayer, 2015). Overall, this would be consistent with the stated goals of natural gas TSOs and DSOs, with the Directive stating that they shall

[60] An important point to note is that, while there is limited experience with the targeted use of demand-side resources to defer natural gas T&D investment, there is significant experience with ratepayer-funded programmes to deliver effective natural gas savings. U.S. and Canadian ratepayer-funded energy efficiency programmes report savings of over 566 million therms (10.7 TWh) of gas in 2017, representing an increase of approximately 16% compared to 2013 levels (Bayer, 2015; CEE, 2019).

"operate, maintain and develop under economic conditions secure, reliable and efficient transmission, storage and/or LNG facilities to secure an open market, with due regard to the environment" (Directive 2009/73/EC, Art.13a).

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14 BUILDING ENERGY PERFORMANCE REQUIREMENTS OF THE IRISH HEAT PUMP SYSTEM GRANT

Country/region	Ireland
Type of E1st approach	D –Behind / Investment 6 – Requiring E1st
Energy carrier(s) targeted	Electricity for heat pumps (and heating oil, natural gas or solid fuels to be substituted with heat pumps)
Sector(s) / energy system(s) or end uses targeted	Residential buildings (heating)
Implementing bodies	Sustainable Energy Authority of Ireland (SEAI)
Decision-makers involved	Irish Government (Department of housing, planning and local government), homeowners (or landlords)
Main objective(s)	General objective: to meet renewable heating targets in the residential sector Complementary objective related to E1st: decreasing the heat loss of a building / dwelling before installing a new heat pump system to allow for it to perform effectively and avoid outsized heating supply. The adaptation of the building envelope prior to an investment decision gives priority to the efficient use of the heating installation.
Implementation period	04/2018 (ongoing)

The Irish government through the Sustainable Energy Authority of Ireland (SEAI) subsidises the installation of heat pump systems if the minimum energy performance of the building has been verified by a mandatory Building Energy Rating (BER, Irish transposition of the Energy Performance Certificates on EU level). If the homeowner did not issue a BER in the past, a technical pre-assessment calculates the BER prior to grant approval to assure the building's energy performance allows for a heat pump system to perform efficiently.

The design of the scheme requires the heat losses of the building envelope to be lower than a maximum Heat Loss Indicator (HLI) for the dwelling to be eligible for the heat pump grant, thus considering energy efficiency aspects prior to supply-side investments. The conditional payment of the subsidy determines the consideration of the E1st principle.

14.1 Background

As part of its climate and energy targets for 2020, Ireland has set a sub-target of 12% renewable heat to help deliver the overall mandatory target of 16% renewable energy by 2020.[61] By 2017, the share of RES heat was about 6.9%[62] (SEAI, 2019). While this represents a doubling of the share of RES heat between 2005 (3.4%) and 2017, it is still not on track to meet the goal. In 2016, Ireland was 27th out of the 28 EU countries for RES heat, with close to 80% of RES heat coming from solid biomass (mainly in industry). The use of ambient energy (through heat pumps) grew ten-fold between 2005 and 2017 to reach approximately 13% of the RES heat consumed in Ireland in 2017. While two thirds of the increase in the share of RES heat between 2005 and 2017 came from an increase in the supply of RES heat, one third came from a decrease in the heat consumption.

> "*This highlights that greater energy efficiency in buildings helps Ireland to meet the national renewable heat target, as well as the binding overall RES target*" (SEAI, 2019).

Ireland has indeed been implementing ambitious energy saving programmes in its residential building sector (which is responsible for 23% of the country's final energy consumption [SEAI, 2018]) to reduce greenhouse gas (GHG) emissions. Space heating in Ireland is still mainly provided by oil (47%), gas (25%) and solid fuels (21%) (SEAI, 2018). The heat pump grant was introduced in April 2018 to increase the share of renewable heat and phase-out fossil-fuel heating systems while reducing heating bills and increasing home comfort levels. Currently, about 6% of heating supply systems (around 108,000 units) in Ireland are replaced or upgraded per year (Keogh et al., 2019), while around 30,000 homes are renovated according to the National Development Plan 2018-2027.

The Irish Heat Pump System Grant has been supporting the market and technological development of heat pump systems for the past two years and is currently operational in all 31 local authorities of Ireland. For installed heat pumps to work efficiently, dwellings have to undergo a mandatory technical assessment of the respective building envelop to assure the energy performance of the building is suitable for a heat pump installation and no outsized heating system is applied. This assessment of the Building Energy Rating (BER) prior to an installation of the heating systems is an example of the E1st principle put into practice in the residential building sector.

The eligibility of the subsidy is dependent on a building heat loss indicator (HLI) of ≤ 2.0 Watts/Kelvin/m² or 2.3 with some caveats. Using this measurement, there are close to 548,000 "heat pump-ready" (HLI of < 2.3) homes built before 2011, according to the national BER registry (Burton, 2019a).

[61] The Directive 2009/28/EC on the promotion of the use of energy from renewable sources set a mandatory overall renewable target for each Member State, but no mandatory target for renewable heat by 2020. The new Directive 2018/2001 requires Member States "*to increase the share of renewable energy in that sector by an indicative 1,3 percentage points as an annual average calculated for the periods 2021 to 2025 and 2026 to 2030, starting from the share of renewable energy in the heating and cooling sector in 2020, expressed in terms of national share of final energy consumption*" (see article 23).

[62] This excludes the share of renewable electricity used for heating or cooling.

14.2 How has the E1st principle (or similar concept) been implemented?

The Irish Heat Pump Grant is part of Better Energy Homes, a comprehensive government programme in operation since 2011, that supports homeowners to improve the energy performance of their houses by subsidising several energy efficiency improvements and the installation of renewable heating systems. The Irish Government aims to accelerate the upgrade of existing buildings to 45,000 renovations per year from 2021 (National Development Plan 2018-2027) to achieve nationally binding energy efficiency and climate targets. Ireland committed to the goal of improving energy efficiency by 20% in 2020 and achieving a 16% renewable energies target (non-ETS CO_2 emission reduction target of 20% based on 2005), contributing to a cost-effective transition to a low-carbon economy in line with EU targets (Burton, 2019b).

The heat pump subsidy incentivises the replacement of old fossil fuel-fired boilers while assuring a minimum energy efficiency of the building. The eligibility criteria of the grant assure an efficient use of the renewable energy system as the technical prerequisites of a heat pump include a BER certification and may require building insulation work prior to heat pump installation. The implementing body, SEAI, provides a registry of BER assessors and a list of registered contractors to ensure high quality installation. The technical energy performance assessment is subsidised by another 200€ under the grant.

14.3 Effects / impacts

In its first year (April 2018-April 2019), the scheme received 550 applications, representing a small share of the overall market of 108,000 units of heating systems replaced per year in Ireland.

An initial monitoring from 2019 found that the heat pumps systems that have been supported by the subsidy are mainly installed in detached single-family houses (75%) with an average size of 190 m² (Burton, 2019a). The “early adopters” were homeowners with houses built in the 1970s on average – half of the cases carried out building insulation work at the same time to fulfil the grant requirements. The average costs amount to 11,250 € including the grant of 3,500€ (Burton, 2019b). This high cost might be linked to the large average size of participant homes.

14.4 Changes over time, if any

The scheme was introduced only recently, so no changes have occurred so far.

14.5 Barriers and success factors

Burton (2019a) highlighted several barriers to the successful implementation of the scheme:

- The limited capacity of SEAI certified contractors. More skilled workers will need trainings on the pre-assessment of heat pump installations to ensure an increased number of granted subsidies (Burton, 2019b).
- The mindset of installers has to adapt to do comprehensive pre-assessments prior to the installation of a heat pump. The installers are responsible for the required assessment of the energy performance requirements, though they also may outsource the process to a technical advisor who is a trained BER assessor and can calculate the Heat Loss Indicator (HLI) and possibly recommend energy performance

improvements such as wall, attic or floor insulation, or the installation of double- or triple-glazed windows. The costs of the technical assessment are supported by 200€, in addition to the 3,500€ subsidy for most heat pump systems (with an exemption for air-to-air pumps).

This shows that implementing the E1st principle in practice might require more cooperation between different trades and/or for professionals to acquire new skills.

Stakeholders, like the Heat Pump Association of Ireland, welcomed the introduction of the grant as an answer to the already growing demand of heat pumps in recent years (Colley, 2018). In particular, the extension of eligibility to houses built before 2011 is seen as an improvement compared to other schemes under the Better Energy Homes programme (Colley, 2018).

14.6 Replicability and scalability potential

The replicability of the grant is theoretically possible in other countries.

In other EU Member States, subsidies for heat pumps are currently not connected to an energy performance requirement or a specific EPC (Energy Performance Certificate) level. In Germany, only the performance of a hydraulic adjustment is a mandatory requirement, while the French government incentivises the exchange of fossil-fuel heating systems leading to a fast deployment of heat pumps without any particular requirement on the energy performance of the building envelope.

Depending on the energy saving targets or a target of renewable heating systems in a country, the scheme may be adapted to the goals of the authorities. A high minimum energy performance standard for eligible homes might slow down the uptake of heat pumps in the country while it can, on the other hand, accelerate energy savings and achieve energy efficiency targets.

The subsidy scheme is replicable in countries with an EPC system and registry in place to identify eligible buildings or monitor the energy performance upgrades. An alternative could be to require an energy audit of the building during the grant application process. In addition, a pool of certified skilled workers and an established training and qualification system ensures high quality of insulation and heating installation.

This type of approach is also replicable to other types of RES systems. For example, SEAI requires that, for a solar PV grant, the energy performance of the dwelling after PV panel installation must be BER C or better (see also example 16). SEAI also recommends the following to applicants for grants for solar water heaters: "*Before considering an investment in solar technologies, it is also important to assess the energy performance of the whole home.*"[63]

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15 FABRIC FIRST APPROACH UNDER THE BETTER ENERGY COMMUNITIES GRANT SCHEME IN IRELAND

Country/region	Ireland
Type of E1st approach	D –Behind / Investment 6 – Requiring E1st
Energy carrier(s) targeted	All energy carriers that can be used for space heating
Sector(s) / energy system(s) or end uses targeted	Residential / public buildings/ commercial
Implementing bodies	Sustainable Energy Authority Ireland (SEAI)
Decision-makers involved	Department of Communication Climate Action and Environment (DCCAE), SEAI and building owners
Main objective(s)	General objectives: improving the energy efficiency of the dwelling stock, reducing the use of fossil fuels, energy costs and GHG emissions. Specific objectives: increasing the ambition of renovation projects by requiring actions on the building envelope before other actions can be eligible to the grant
Implementation period	2012 – ongoing (Fabric first required since 2017)

The Better Energy Communities (BEC) scheme is one of the main grant schemes administered by the Sustainable Energy Authority of Ireland and aims at reducing the fossil fuel usage, energy costs and GHG emissions of the national building stock. The BEC scheme, which started in 2012, supports community-oriented innovative projects from various sectors, including residential housing upgrades and non-residential building works, and accepts applications from commercial and voluntary organisations, the public sector and private homeowners. Projects should achieve an energy performance level of a B2 (minimum C1 to receive funding) and are required to follow a *Fabric first* approach.

15.1 Background

The residential sector represents 23% of Ireland's final energy consumption. The stock includes about 1.7 million dwellings, 50% of which was built before 1981 (the first building requirements were set in 1979). Space heating represents about 61% of the residential energy use, which in Ireland is still mainly provided by oil (47%), gas (25%) and solid fuels (21%) (SEAI, 2018a). This explains why reducing GHG emissions is a key objective of the energy efficiency programmes.

Ireland has been implementing energy saving programmes in the residential sector since 2000. 375,000 homes received government grants for energy efficiency measures between 2000 and 2016, i.e., about 22% of the dwelling stock. Energy efficiency in households improved by 32% between 2000 and 2016; the average specific final energy consumption of dwellings was reduced from 230 to 156 kWh/m².year (SEAI, 2018a).

Ireland introduced ambitious building renovation targets in their Climate Action Plan 2019 to try to reach the energy efficiency target of 20% in 2020, which was likely to be missed by 3-4% with the trends observed at that time (SEAI 2019a). The government set the goal of upgrading the energy performance of 500,000 buildings to a B2 Building Energy Rating (BER) by 2030, which would require the renovation of 50,000 houses annually beginning in 2021.

Since 2011, the Better Energy programme has been the main government scheme to support multiple energy efficiency upgrades and renewable energy installations with different grants for residential homeowners depending on the type of renovation works (Better Energy Homes) and the applicant's situation (Better Energy Warmer Homes). The Better Energy Homes scheme, for instance, includes specifications that are used by the other schemes (minimum requirements per action type, register of contractors qualified for the scheme).

The second largest grant programme is the Community Grant, specifically the Better Energy Communities scheme, which was introduced in 2012. This national renovation scheme supports community-oriented energy efficiency projects through capital funding, partnerships and technical support and accepts projects from housing associations, the private and public sector (public and commercial buildings) as well as community-based organisations. SEAI publishes a new call for proposals and related Application Guidelines every year (see SEAI 2019b, 2018b and 2017), often with minor changes to the requirements and additional pilot schemes.

15.2 How has the E1st principle (or similar concept) been implemented?

SEAI implicitly includes an E1st approach in the funding requirements of the Better Energy Communities scheme. SEAI uses the requirements of the €19 million budget (provisionally 2020) BEC grant scheme to increase the ambition of the energy efficiency improvements in the building sector, so that most of the renovations achieve the target level of B2 Building Energy Rating.

Projects that apply for funding under the grant scheme are required to demonstrate that energy efficiency improvements (wall insulation, roof insulation, upgrade of windows and doors) are given priority over the installation of renewable heating systems or other smart technologies. This Fabric first criterion is only mandatory for residential projects, acknowledging that it is not always a practical solution for non-domestic projects. In any case, the eligibility criteria communicate a strong focus on energy efficiency measures.

Funding varies between €50,000 and €1,500,000 per project, and the level of subsidies depend on the type of building and occupants. Private non-energy poor or local authority homes can receive up to 35% of the total costs, while energy-poor private homeowners can receive up to 80%.

The E1st concept has been applied in the Residential Combined Fabric Upgrade, a pilot additional support package tested in 2017. The Combined Fabric Upgrade releases a financial bonus (15% of additional support) when ALL fabric-related measures under Step 1 are carried out and lead to higher building energy performance, before upgrading heating installations (step 2) or applying additional renewable installations (step 3). The measures of Step 1 are roof insulation, external wall insulation, full window replacement, external door replacement, minimum air permeability test performance and ventilation requirements of a mechanical ventilation system (SEAI, 2017). Credits for Steps 2 and 3 are only released when all measures of Step 1 are carried out demonstrating the priority put on investments that reduce heat demand over investments that improve the efficiency of heat supply.

In addition, only when all measures were carried out to meet the minimum technical and energy efficiency specifications of the scheme as listed in the guidelines was a bonus provided. Though this pilot scheme was only tested in 2017, the rationale behind this *Fabric first approach* was transferred to the following funding cycles.

Since 2017, applicants are required to demonstrate that energy efficiency measures will be given priority to be deemed an eligible project, and since 2019, eligible projects must demonstrate a post-renovation Building Energy Rating (BER) of B2. Applicants might still receive funding if there are adequate reasons for not achieving the B2 level, though this is the exception. This approach supports the goal of attaining energy efficiency first, with renewable and smart technologies playing a secondary role.

15.3 Effects / impacts

The Fourth National Energy Efficiency Action Plan from 2017 states that the BEC scheme provided over €16 million in grant funding for energy efficiency upgrades in 2016 to more than 2000 homes and close to 300 community and commercial buildings (DCCAE, 2017). An investment of €55 million was leveraged in total, supporting over 700 direct and indirect jobs across Ireland. In total, more than 15,000 homes and hundreds of communities, private and public buildings have received energy efficiency upgrades.. There is no information publicly available yet about the specific impacts of the requirements related to the Fabric first approach. However, SEAI observed a decrease in the number of applications (especially from product manufacturers) and an increase in the average investment and number of measures per project. This data shows that the new requirements have helped to encourage more ambitious projects. For more details, see the section about barriers and success factors below.

15.4 Changes over time, if any

The Better Energy Communities scheme was introduced in 2012 as an innovative grant scheme supporting large-scale energy efficiency improvement projects, including demonstration projects and projects alleviating energy poverty. The aim was also to trigger the implementation of deeper and more technically and economically challenging measures than is possible under other grant schemes.

The 2017 scheme cycle was officially launched in December 2016 with a budget of €30 million in grant support for community energy projects. This presented a 50% increase in funding compared to the 2016 level. Moreover, the Residential Combined Fabric Upgrade Package was introduced, providing bonus grant funding for homeowners who engage in a combined fabric upgrade that involves a significant energy efficiency upgrade to their home as explained above. This pilot only ran during the 2017 grant cycle. Since 2017, this Fabric first approach is now required in order to prevent inappropriate and expensive renewable heating systems or other energy services of being installed without improving the energy performance of the building envelope. In the previous years, SEAI had noticed a trend of product manufacturers proposing projects which focused on their products rather than what was necessary for the buildings in question (Flynn, 2020a; Flynn, 2020b). SEAI thus decided to implement the Fabric first approach progressively:

- In 2017, contractors were requested to follow the Fabric first approach by first addressing the building envelope before other work can be eligible for grants.
- In 2018, projects were requested to achieve at least a B2 rating, or to explain why it was not feasible to do so.
- From 2019 on, projects must achieve at least a B2 rating to be eligible for funding (a C1 level is exceptionally possible under certain conditions).

This ensures that contractors only propose work to buildings which address the efficiency needs of the buildings, building owners and occupants. The requirement of a high energy performance level also ensures that contractors have to focus on the building envelope first. This level can rarely be met by only improving the heating system (except if the building envelope is already well insulated).

15.5 Barriers and success factors

With its long experience with designing and administering a grant scheme for the residential sector, SEAI can build on existing knowledge and create synergies between the programmes. The proven technical requirements and specifications and the professional execution of the measures (via registered qualified contractors) from the Better Energy Homes schemes is a success factor the BEC scheme can benefit from. Over the years, SEAI has been fine-tuning its approach and funding requirements to accelerate energy renovations. The requirements to carry out comprehensive insulation measures to increase energy performance of the building envelop are more complex and cost-intensive than a single replacement of a heating system. This resulted in a 50% decrease in project applications with the introduction of the Fabric first requirement, mostly due to fewer applications by product manufacturers who earlier designed projects to promote their products and technologies.

A positive effect of the new requirements was that the number of measures and total costs per building increased significantly in recent years, in line with the objective of the scheme to encourage ambitious renovation projects. Though the increased costs had a significant impact on the project volume right after their implementation, SEAI now sees new interest in the Fabric first approach by experienced contractors. The new technology is indeed becoming more acceptable and the costs are moderating (Flynn, 2020a).

15.6 Replicability and scalability potential

With the residential sector responsible for 23% of final energy consumption and ambitious renovation targets in place, the Fabric first approach is an important feature in Irish building renovation and is applied across grant schemes.

The other energy efficiency grant schemes implemented by SEAI also follow the Fabric first approach, more or less explicitly:

- the scheme information always recommends to start the project by looking at the energy performance of the building.
- the grants first highlighted in the SEAI communication on grants for households are the ones for insulation actions.
- the grants available for heat pumps include a technical prerequisite that the building must have a minimum efficiency (BER) level (see the example about the SEAI Heat Pump Grant).

The replicability of the approach to other European countries is theoretically possible given high energy efficiency targets. Although other countries did not explicitly implement a *Fabric first* approach in their grant schemes, the replicability potential is high. Other financial schemes enable higher amounts of funding for higher energy performance, such as the KfW loan programme “Energieeffizient Sanieren” in Germany, which gives out higher repayment subsidies for higher energy performance standards (30% for KfW-Effizienzhaus 85, 40% for KfW-Effizienzhaus 55).

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16 LINKING RENEWABLE SUPPORT TO BUILDING ENERGY PERFORMANCE

Country/region	Great Britain
Type of E1st approach	D –Behind / Investment 6 – Requiring E1st
Energy carrier(s) targeted	Electricity
Sector(s) / energy system(s) or end uses targeted	Residential/service sector/public sector
Implementing bodies	OFGEM (national regulator)
Decision-makers involved	Building owners
Main objective(s)	Incentivising the improvement of building energy performance by conditioning the eligibility for feed-in tariff on energy performance level
Implementation period	2012-2019

Optimising distributed renewable investment along with energy efficiency seems to be a common-sense approach: it makes sense to size on-building renewable (or other) generation capacity to the demand that is already reduced to a cost-efficient minimum. Conditioning public support for distributed energy supply on a predefined minimum level building energy performance is an implementation of the E1st principle with a large scalability potential. This case is about linking feed-in tariff in the UK to minimum building standard.

16.1 Background

The support for building integrated distributed generation in Europe mainly concerns the investment and/or operational support for small-scale PV panels. The three main forms of production-based (operational) support for renewables are net metering, feed-in tariffs (FIT) or green certificates.

The FIT scheme was introduced in Great Britain (i.e., not including Northern Ireland) by the Department of Energy and Climate Change (DECC) in April 2010 (OFGEM, 2016). It replaced the Renewables Obligation (RO) as the main support for PV, wind and hydro generation units of 50kW or less. Eligible small-scale generators with a capacity between 50kW and 5MW have a one-off choice of applying under the FIT or the RO.

The FIT scheme created an obligation for certain electricity suppliers to make tariff payments for generating and exporting renewable and low-carbon electricity to the grid. The scheme ceased to operate in 2019.

16.2 How has the E1st principle (or similar concept) been implemented?

The regulatory drive behind the FIT scheme was the uptake of small-scale renewables generation. E1st was implemented as a condition of eligibility for the FIT scheme. There were several eligibility criteria for capacity units in the scheme:

- the site.
- the capacity of the generating unit.
- the commissioned date.
- the implications of Non-Fossil Fuel Obligation (NFFO)/Scottish Renewables Obligation (SRO) contracts extensions.
- energy efficiency requirements.
- benefits for Community Organisations and Education Providers.
- multi-installation tariffs.
- the combination of FITs and grants.

The energy efficiency requirement applied only to PV installations of 250kW or less wired to a building (defined as a roofed construction which has walls and where energy is used to condition the indoor climate, whether heating or cooling systems), or providing electricity to one or more such buildings.

FIT applicants had to demonstrate that the building has an Energy Performance Certificate (EPC) rating of level D or above to receive the higher tariff. If the EPC was in the band E, F or G, the applicant either had to carry out energy efficiency improvements before applying for the FITs or accept the lower rate for the lifetime of the tariff (20 years). The FIT scheme included three tariffs: higher, middle and lower. The higher level applied in the case of an EPC of level D or above and if the owner did not have 25 or more installations. If the owner had 25 or more installations, than it could only receive the middle tariff. The tariffs have been digressing quarterly due to the reducing cost of PV. As different levels apply to the various capacity bands (5 bands between 4 kW to 250 kW), their reduction due to low energy performance is a varying sum: in case of 0-4 kW units the lower tariff was approximately half of the higher tariff (OFGEM).

The GB Energy Performance of Buildings Regulations require an EPC whenever a building is constructed or marketed for sale or rent. The certificate gives an asset rating which indicates how energy efficient a building is. For the purposes of receiving the higher FIT, the energy efficiency rating band of the certificate needed to be considered (and not the environmental impact rating band). Community energy and school installations were permitted to receive the higher tariff with a lower EPC rating if certain conditions were met. An EPC was accepted only if 1) it was issued before the commissioning date of the PV unit (but less than 10 years before as this is the expiry of the EPCs) and 2) it was the most recent EPC that had been issued for the building. The application needed to be submitted to the national regulatory agency, OFGEM.

Even though the energy demand measured by the EPC (mainly heating demand) is not directly supplied by the generation it is linked to in the scheme (PV is either insufficient or not used at all to meet heating demand), rerouting households to prioritise energy efficiency investment over distributed generation within their own budget still holds the logic of E1st.

16.3 Effects / impacts

There is limited evidence of the impact of conditioning the higher-level feed-in tariff on the energy performance of the building it is wired to. A 2015 review assessing the FIT scheme claimed that the uptake of energy efficiency measures in properties with solar PV units between 2010 and 2013 revealed that the share of properties with at least one energy efficient measure installed increased from 56% to 61%, suggesting an increased level of energy awareness that could be attributed to the energy performance criteria introduced to the FIT scheme in 2012 (Nolden, 2015). Data from 2015 showed that 86% of households with solar PV installations had at least one energy efficiency measure installed, most frequently cavity wall and loft insulation.

16.4 Changes over time, if any

The feed-in scheme in GB was closed in March 2019 to new applicants (existing eligibility is not affected by this change); from 2020 onwards, small-scale renewable installations[64] are supported by a new scheme called Smart Export Guarantee (SEG). Under this scheme, all licenced energy suppliers with 150,000 or more customers must provide at least one Smart Export Guarantee tariff. Smaller suppliers can offer a tariff if they want to on a voluntary basis. A condition of eligibility is that power exported to the grid must be metered using a meter capable of reading exports on a 30-minute basis, even if this granularity is not required for the tariff and the same meter must be registered for the settlement. Suppliers would determine both the tariff per kWh and the length of the contract. The tariff must be greater than zero; at times of negative pricing, eligible renewable producers cannot be required to remunerate suppliers for electricity exported to the grid (BEIS, 2019).

However, unlike the feed-in tariffs scheme, there will not be a requirement for properties to meet minimum energy efficiency standards. There was no reasoning provided in the new regulation for terminating this condition. A possible reason might be that public/ratepayer money will no longer be used for supporting PVs (as in the case of FIT), but the suppliers are to offer a price for the electricity exported to the grid in a bilateral private contract with the consumer. As such, the room for public intervention is limited.

16.5 Barriers and success factors

Linking renewable support to building energy performance requires a credible, easy to acquire certification scheme in place. This is both the main success factor and main barrier. EPC is a tool that has been already implemented, independent of the renewable support scheme. The regulatory move to link the two is a virtually no-cost change, requiring just the addition of an energy efficiency condition to the list for feed-in tariff eligibility. However, if the EPC is not credible then it can act as a barrier for the successful implementation of E1st.

[64] Solar PV systems, onshore wind, anaerobic digestion, hydro – up to 5MW; micro-combined heat and power – with an electrical capacity of up to 50kW.

16.6 Replicability and scalability potential

As long as there is support for renewable installation wired to buildings, the option of linking it to a predefined energy performance standard or a set of energy efficiency improvements can be incorporated easily into the regulations. Despite the fact that renewable support cannot – by default – be supported by feed-in tariffs due to EU state aid legislation, several countries have opted for the flexibility offered in the EU rules with regard to small-scale units and retained the FIT scheme. Similar conditions could apply to investment support provided by the state for small RES installations. EU Member States that are eligible for EU cohesion fund support often offer such support in the frame of tenders financed form EU funds.

16.7 Sources and references

Web sources:

OFGEM Feed-In Tariff (FIT) tables: https://www.ofgem.gov.uk/environmental-programmes/fit/fit-tariff-rates

References:

BEIS (2019). The Future for Small-scale Low Carbon Generation: A consultation on a Smart Export Guarantee. Department for Business, Energy & Industrial Strategy, January 2019.

Nolden, C. (2015). Performance and Impact of the Feed-in Tariff Scheme: Review of Evidence. Report of the Sussex University for the DECC (Department of Energy and Climate Change)

OFGEM (2016). Feed-in Tariff: Guidance for renewable installations (Version 10.2). Ofgem (UK Office of Gas and Electricity Markets) Guidance, 20 June 2016.

17 FURTHER EXAMPLES FROM OTHER SOURCES

Further examples can be found in the literature and are gathered in the table below. This list does not pretend to be exhaustive. It aims at providing complementary sources for readers interested in finding more examples about the implementation of the Efficiency First principle or similar concepts.

Table 9 – Further examples from other sources

No	Example (and source)	Type of provisions	Level of requirement	Region / Country	Targeted energy carrier(s)
17.	Holyhead Powersave Project (Rosenow et al., 2016)	B. In front/ Investment	1. Allowing E1st	UK (Wales)	Electricity
18.	French Riviera “Eco-Energy Plan” (Rosenow et al., 2016)	B. In front/ Investment	1. Allowing E1st	France	Electricity
19.	C2C Capacity to Consumers (Rosenow et al., 2016)	A. In front/ General	2. Enabling E1st	UK	Electricity
20.	Krakow Energy Efficiency Project (Rosenow et al., 2016)	D. Behind/ Investment	1. Allowing E1st	Poland	Heat
21.	Early Energy Efficiency Obligation Schemes to include energy efficiency in the regulatory framework	A. In front/ General	6. Requiring E1st	UK and Denmark	Electricity and gas
22.	EU-wide Covenant of Mayors for Climate & Energy (Rosenow et al., 2016)	B. In front/ Investment	3. Requiring E1st-proof assessments	EU	All
23.	Early time-of-use tariffs (Rosenow et al., 2016)	A. In front/ General	1. Allowing E1st	Poland, France	Electricity
24.	Loire time-of-use tariff (Rosenow et al., 2016)	B. In front/ Investment	1. Allowing E1st	France	Electricity
25.	Energy efficiency as infrastructure in Scotland (Rosenow et al., 2016)	C – Behind / General	6. Requiring E1st	UK (Scotland)	All
26.	Czech Green Savings Programme (Rosenow et al., 2016)	D. Behind/ Investment	5-Encouraging E1st	Czech Republic	All
27.	Minimum energy efficiency requirement prior to renewable energy installation (Rosenow et al., 2016)	D. Behind/ Investment	6. Requiring E1st	UK and Flanders	All
28.	The eFlex Project (pilot project about demand response and heat pumps) (Dong Energy, 2012)	A. In front/ General	1. Allowing E1st	Denmark	Electricity
29.	Energy efficiency as a means to expand energy access (de la Rue du Can et al. 2018)	B. In front/ Investment	2. Enabling E1st	Uganda	Electricity
30.	Energy efficiency as a resource in the ISO New England forward capacity market (Jenkins et al., 2011 ; Rosenow and Liu, 2018; SENSEI 2020)	A. In front/ General	2. Enabling E1st	US (New England)	Electricity
31.	Ontario Save on Energy – Energy Performance programme (SENSEI 2020) (part of the Conservation First policy (Ontario 2013))	D. Behind/ Investment	5-Encouraging E1st	Canada (Ontario)	Electricity and natural gas
32.	NYSERDA’s Business Energy Pro programme (SENSEI 2020)	D. Behind/ Investment	5-Encouraging E1st	US (State of New York)	Electricity and natural gas
33.	Pacific Gas and Electric Company (PG&E)’s Residential Pay-for-Performance Programmes (SENSEI 2020)	A. In front/ General	6. Requiring E1st	US (California)	Electricity and natural gas
34.	UK Electricity Demand Reduction Pilot (SENSEI 2020)	A. In front/ General	2. Enabling E1st	UK	Electricity

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Rosenow, J., and Liu, Y. (2018). ISO (Independent System Operators) New England Capacity Market. Case study prepared for the EPATEE project, funded by the European Union's Horizon 2020 programme.

Rosenow, J., Bayer, E., Rososińska, B., Genard, Q., and Toporek, M. (2016). Efficiency First: From Principle to Practice with Real World Examples from Across Europe. Report of the Regulatory Assistance Project, November 2016.

SENSEI (2020). Experience and lessons learned from P4P pilots for energy efficiency. Deliverable D4.4 of the SENSEI project, funded by the European Union's Horizon 2020 programme, June 2020.

References about the examples

They can be found at the end of each example (see section x.7 in each example).