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Optimization and Simulation Based Cost-Benefit Analysis on a Residential Demand Response: Applications to the French and South Korean Demand Response Mechanisms

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THÈSE DE DOCTORAT

DE L'UNIVERSITÉ PSL

Préparée à Université Paris-Dauphine

**Optimization and Simulation Based Cost-Benefit Analysis
on a Residential Demand Response: Applications to the
French and South Korean Demand Response Mechanisms**

Soutenue par

Seungman LEE

Le 3 décembre 2019

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THÈSE POUR L'OBTENTION DU
DOCTEUR EN SCIENCES ÉCONOMIQUES

Présentée et soutenue par

Seungman LEE

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Abstract

Worldwide concern on CO₂ emissions, climate change, and the energy transition made us pay more attention to Demand-side Management (DSM). In particular, with Demand Response (DR), we could expect several benefits, such as increased efficiency of the entire electricity market, enhanced security of electricity supply by reducing peak demand, and more efficient and desirable investment as well as the environmental advantage and the support for renewable energy sources. In Europe, France launched the NEBEF mechanism at the end of 2013, and South Korea inaugurated the market-based DR program at the end of 2014. Among a number of economic issues and assumptions that we need to take into consideration for DR, Customer Baseline Load (CBL) estimation is one of the most important and fundamental elements. In this research, based on the re-scaled load profile for an average household, several CBL estimation methods are established and examined thoroughly both for Korean and French DR mechanisms. This investigation on CBL estimation methods could contribute to searching for a better and accurate CBL estimation method that will increase the motivations for DR participants. With those estimated CBLs, the Cost-Benefit Analyses (CBAs) are conducted which, in turn, are utilized in the Decision-making Analysis for DR participants. For the CBAs, a simple mathematical model using linear algebra is set up and modified in order to well represent for each DR mechanism's parameters. With this model, it is expected to provide an intuitive and clear understanding of DR mechanisms. This generic DR model can be used for different countries and sectors (e.g. residential, commercial, and industrial) with a few model modifications. The Monte Carlo simulation is used to reflect the stochastic nature of the reality and the optimization is also used to represent and understand the rationality of the DR participants, and to provide microeconomic explanations on DR participants' behaviors. In order to draw some meaningful implications for a better DR market design, several Sensitivity Analyses (SAs) are conducted on the key elements of the model for DR mechanisms.

Keywords: Demand Response (DR), Customer Baseline Load (CBL), Cost-Benefit Analysis (CBA), Monte Carlo Simulation, Optimization, Sensitivity Analysis (SA), NEBEF, Load Aggregator (LA)

Résumé

À cause de la préoccupation mondiale sur les émissions de CO₂, le changement climatique, et la transition énergétique, nous faisons plus d'attention à la maîtrise de la demande d'électricité. En particulier, avec l'effacement de consommation électrique, nous pouvons profiter de plusieurs avantages, comme l'augmentation de l'efficacité de l'ensemble du marché de l'électricité, la sécurité d'approvisionnement d'électricité renforcée, et l'investissement plus efficace et souhaitable ainsi que l'avantage de l'environnement et le soutien aux énergies renouvelables. En Europe, la France a démarré le mécanisme de NEBEF à la fin de 2013, et la Corée du Sud a lancé le programme de l'effacement de consommation électrique basé sur le marché fin 2014. Parmi un certain nombre de questions et d'hypothèses que nous devons prendre en compte en termes de l'effacement, l'estimation de la courbe de référence est l'un des éléments les plus importants et les plus fondamentaux. Dans cette recherche, sur la base du profil de consommation redimensionné pour un ménage moyen, plusieurs méthodes d'estimation de la courbe de référence sont établies et examinées à la fois pour les mécanismes de l'effacement français et coréen. Cette investigation sur les méthodes de l'estimation pourrait contribuer à la recherche d'une méthode d'estimation meilleure et plus précise qui augmentera les motivations pour les participants. Avec les courbes de référence estimées, les analyses coûts-bénéfices ont été réalisées, elles-mêmes utilisées dans l'analyse décisionnelle pour les participants. Pour réaliser les analyses coûts-bénéfices, un modèle mathématique simple utilisant l'algèbre linéaire est créé et modifié afin de bien représenter les paramètres de chaque mécanisme de l'effacement. Ce modèle nous permet une compréhension intuitive et claire des mécanismes. Ce modèle générique peut être utilisé pour différents pays et secteurs, résidentiel, commercial et industriel, avec quelques modifications de modèle. La simulation de Monte Carlo est utilisée afin de refléter la nature stochastique de la réalité, et l'optimisation est également utilisée pour représenter et comprendre la rationalité des participants, et pour fournir des explications microéconomiques sur les comportements des participants. Afin de dégager des implications significatives pour une meilleure architecture du marché de l'effacement, plusieurs analyses de sensibilité sont effectuées sur les éléments clés du modèle pour les mécanismes.

Mots-clés: l'Effacement de Consommation Électrique, la Courbe de Référence, l'Analyse Coûts-Bénéfices, la Simulation Monte Carlo, l'Optimisation, l'Analyse de Sensibilité, NEBEF, l'Opérateur d'Effacement

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List of Glossaries

event day	The day in which there is a call or order from the DR system operator to activate the DR program, and as a result, there will be an actual reduction of electricity consumption.	62
reference days	10 or 20 days. The candidates for the similar non-event days. To choose the reference days, the prior DR event days, holidays, weekends will be excluded, and only ordinary working week-days are included.	62
similar non-event days	The days that are used in the computation of CBL, and it does not include the previous DR event days.	62

Acronym & Abbreviation

ADCR	Active Demand Capacity Resource	25
ADR	Active Demand Response	12
AMI	Advanced Metering Infrastructure	18
ARE	Average Relative Error	64
BRP	Balancing Responsible Party	34
CAISO	California Independent System Operator	25
CBA	Cost-Benefit Analysis	7
CBL	Customer Baseline Load	7
CBP	Cost-based Pool	7
CCM	Capacity Credit Market	26
CEA	Cost-Effectiveness Analysis	93
CPP	Critical Peak-Pricing	12
CPUC	California Public Utilities Commission	93
CRE	La Commission de Régulation de l'Énergie	34
CRM	Capacity Remuneration Mechanism	1
CSP	Curtailment Service Provider	26
DADRP	Day-Ahead Demand Response Program	25
DLC	Direct Load Control	12
DOE	Department of Energy	4
DR	Demand Response	1
DRA	Demand Response Asset	25
DRM	Demand Response Mechanism	7
DRR	Demand Response Resource	25
DRTM	Demand Resource Trading Market	50
DSASP	Demand-Side Ancillary Services Program	25
DSM	Demand-side Management	1
DSO	Distribution System Operator	14
DSR	Demand-side Response	11
ED-CPP	Extreme Day Critical Peak-Pricing	12
EDE	Entité d'Effacement	78
EDF	Électricité de France	33
EDP	Extreme Day Pricing	12
EDRP	Emergency Demand Response Program	25
EE	Energy Efficiency	11
EnRv	énergies renouvelables à apports variables	228
EPEX	European Power Exchange	55
EPRI	Electric Power Research Institute	93
EPSIS	Electric Power Statistics Information System	47
ERCOT	Electric Reliability Council of Texas	25
FCM	Forward Capacity Market	25
FCR	Frequency Containment Reserves	33

FERC	Federal Energy Regulatory Commission	10
GHG	Greenhouse Gas	2
IBP	Incentive-based Program	12
ICAP/SCR	Installed Capacity – Special Case Resource	25
ICT	Information and Communication Technology	18
IEA	International Energy Agency	5
IRP	Integrated Resource Planning	11
ISO	Independent System Operator	10
ISO-NE	ISO New England	25
JRC	Joint Research Centre	93
KEEI	Korea Energy Economics Institute	47
KEPCO	Korea Electric Power Corporation	1
KPX	Korea Power Exchange	50
LA	Load Aggregator	14
LBMP	Locational-Based Marginal Price	26
LDC	Load Duration Curve	36
LMP	Locational Marginal Price	26
LPA	Load Point Adjustment	26
MAPE	Mean Absolute Percentage Error	64
MCP	Medium Combustion Plant	54
MCPD	Medium Combustion Plant Directive	54
MOTIE	Ministry of Trade, Industry and Energy	2
NAESB	North American Energy Standards Board	62
NBT	Net Benefit Test	34
NBTP	Net Benefit Test Price or Net Benefit Threshold Price	34
NEBEF	La Notification d'Échange de Blocs d'Effacement	34
NERC	North American Electric Reliability Corporation	10
NYISO	New York Independent System Operator	25
PAC	Proportional Adjustment Coefficient	70
PBP	Price-based Program	12
PDR	Proxy Demand Resource	26
PJM	PJM Interconnection	10
PR	Primary Reserve	33
PRD	Price Responsive Demand	25
PTR	Peak Time Rebate	13
PURPA	Public Utility Regulatory Policy Act	24
RDRR	Reliability Demand Response Resource	26
RES	Renewable Energy Source	2
RMSE	Root Mean Square Error	65
RPM	Reliability Pricing Model	26
RRMSE	Relative Root Mean Squared Error	51
RTE	Réseau de transport d'électricité	33

RTO	Regional Transmission Operator	10
RTP	Real-time Pricing	12
SA	Sensitivity Analysis	7
SAA	Symmetric Additive Adjustment	62
SEDC	Smart Energy Demand Coalition	18
SG	Smart Grid	16
SMP	System Marginal Price	51
ToU	Time-of-Use	12
TSO	Transmission System Operator	14
VPP	Variable Peak Pricing	13
WMA	Weighted Moving Average	63
WSA	Weather Sensitivity Adjustment	62
WTA	Willingness-to-Accept	107

Notation & Nomenclature

β	the relative ratio of inconvenience to the unit present value of the electricity consumption at the DR event time	108
Cap	a vector of the capacity factor, which represents the potential capacity to accept some part of the total required load reduction. In order to represent ‘stochastic’ capacity, individual property, daily condition, it is ‘random number (pseudorandom number)’ from uniform distribution between ‘0’ and required flexibility level (RFL). Cap $\sim U(0, \text{RFL})$ $0 \leq \text{Cap}_t \leq \text{RFL}$, $t \in T = \{1, 2, \dots, 24\}$	98
$\text{CBL}_{d,t}$	customer baseline load for the DR event day, d, at the event time, t, $d \in D = \{1, 2, \dots, 365\}, t \in T = \{1, 2, \dots, 24\}$, $\sum_{i=1}^n (\omega_i \times \ell_{d-i,t})$	63
CBL^{avg}	a vector of CBL established with simple average method	62
$\text{CBL}^{\text{avg.4}}$	a vector of CBL which is calculated with the method of ‘Moyenne 4 jours’	82
$\text{CBL}^{\text{avg.10}}$	a vector of CBL which is calculated with the method of ‘Moyenne 10 jours’	80
$\text{CBL}^{\text{med.4}}$	a vector of CBL which is calculated with the method of ‘Médiane 4 jours’	82
$\text{CBL}^{\text{med.10}}$	a vector of CBL which is calculated with the method of ‘Médiane 10 jours’	80
$\text{CBL}^{\text{WMA}} \cdot \text{PAC}$	a vector of proportionally adjusted CBL	70
$\text{CBL}^{\text{WMA}} + \text{SAA}$	a vector of CBL with Symmetric Additive Adjustment	71
CBL^{WMA}	a vector of CBL established with the weighted moving average method	70
Coef^{INC}	a vector of generalized coefficients representing additional inconvenience of load shedding (or load shifting), $t \in T = \{1, 2, \dots, 48\}$	124
$\text{Coef}_t^{\text{dINC}}$	a generalized inconvenience coefficient for each time slot, $t \in T = \{1, 2, \dots, 48\}$	125
d	a vector of time distance from DR event time to shifted time slot, $t \in T = \{1, 2, \dots, 24\}$	108
$\ell_{d,t}$	actual load at the time slot t and on the day of d, $d \in D = \{1, 2, \dots, 366\}, t \in T = \{1, 2, \dots, 24\}$.	69
INC_t	additional inconvenience costs, $t \in T = \{1, 2, \dots, 24\}$	108

$\ell_{d-i,t}$	actual load at the time of t , and on the day of $d - i$ (i^{th} day before the DR event day)	63
ℓ	a column vector consisting of the actually consumed load without DR for each time slot, $t \in T = \{1, 2, \dots, 24\}$	100
ℓ'	a column vector consisting of the actually consumed loads with DR for each time slot, $t \in T = \{1, 2, \dots, 24\}$, if we consider only load shifting, not load shedding, then the total electricity consumptions remain the same with DR event and without DR event, $\mathbf{1}_{24}^T \ell = \mathbf{1}_{24}^T \ell'$ that is, $\sum_{t=1}^{24} \ell_t = \sum_{t=1}^{24} \ell'_t$ where, $\mathbf{1}_{24}^T$ is a sum vector with all the elements of 1	98
$\mathbf{L}_{366 \times 24}^{\text{agg.}}$	a matrix of aggregate loads, 366 rows \times 24 columns, in 2016 (there were 366 days in 2016)	69
$\mathbf{L}_{366 \times 144}^{\text{agg.}}$	a matrix of aggregate loads of France measured for every 10 minutes, 366 rows \times 144 (=24 \times 6) columns, in 2016 (there were 366 days in 2016)	78
$\mathbf{L}_{366 \times 48}^{\text{agg.}}$	a matrix of aggregate loads of France measured for every 30 minutes, 366 rows \times 48 (=24 \times 2) columns, in 2016 (there were 366 days in 2016)	78
$\mathbf{L}_{366 \times 24}^{\text{avg.res.}}$	a matrix of rescaled loads of an average household in (Wh), 366 rows \times 24 columns	69
$\mathbf{L}_{366 \times 48}^{\text{avg.res.}}$	a matrix of rescaled loads of an average household of France in (Wh), 366 rows \times 48 (=24 \times 2) columns	78
MinBase	minimum base load defined as the fifth percentile of the cumulative density distribution of all the hourlyload for the maximum reference days (20 days prior to the event day)	95
ω_i	a weight for i^{th} day before the DR event day.	63
ω^T	a transposed vector of the weights for i^{th} day before the DR event day,	70
\mathbf{p}	a column vector consisting of the retail price for each time slot, $t \in T = \{1, 2, \dots, 24\}$	98
\mathbf{p}^u	a column vector consisting of the retail price with uniform tariff scheme for each time slot, $t \in T = \{1, 2, \dots, 24\}$	105
\mathbf{p}^{tou}	a column vector consisting of the retail price with Time-of-Use tariff scheme for each time slot, $t \in T = \{1, 2, \dots, 24\}$	105
PAC	Proportional Adjustment Coefficient for the weighted moving average method	70
ϕ	the proportion to SMP for a residential participant, therefore, the proportion to SMP for a load aggregator is $(1 - \phi)$, $0 \leq \phi \leq 1$	98
\mathbf{r}'	a vector of actualized load reduction, $\Delta = \mathbf{CBL} - \ell'$ (actualized load with DR)	98

RFL	required flexibility level, such as, 0.2 (20%), 0.3 (30%), 0.4 (40%), or 1 (max)	98
S^4	a matrix of the similar non-event 4 days	82
S^6	a matrix of the similar non-event 6 days	70
S^{10}	a matrix of the similar non-event 10 days	80
SAA	additive adjustment coefficient for the SAA option	71
SMP	a vector of SMP	98
θ	ratio of the cost differential over the benefit differential between two cases, DR participation and no DR participation (status quo), $\frac{\Delta(C_1 - C_0)}{\Delta(B_1 - B_0)} = \frac{\Delta C}{\Delta B}$	110
t_e	DR event ending time	64
t_s	DR event starting time	64
v	a vector of transfer ('versement') to the electricity supplier.	120
x	a column vector consisting of the proportions to the total required load reduction that will be shifted to other time slots, $t \in T = \{1, 2, \dots, 24\}$, except 17h and 18h	98

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§Chapter 1

Introduction: Electricity Demand and Role of Demand Response

1.1 Background

If the electricity market is perfect, that is, perfect information and no transaction costs, then the supply and demand for electricity always meet, and there is no need for other complementary mechanisms (Keppler, 2014b, p. 7). However, in the real world, the market is not fully competitive and liberalized, and there are market failures. As a result, there is an imbalance between the supply of electricity and the demand for electricity. In other words, the energy-only markets cannot provide the ‘adequate level of the capacity for electricity’. The energy-only markets do not send the right signal for investors to invest in politically and socially desirable levels of capacity (Keppler, 2014b, p. 3).

In order to ensure the security of the electricity supply, there are two approaches to the solutions.^[1] The first one is dealing with the supply side. For instance, we could come up with increasing the capacity or using the [Capacity Remuneration Mechanisms \(CRMs\)](#). Another is managing the demand-side and employing involuntary or voluntary [Demand Response \(DR\)](#) programs. Many advanced countries, such as the U.S. and western European countries, have already introduced [Demand-side Management \(DSM\)](#) programs and confirmed its positive functions, benefits, and effects. The stakeholders and policy-makers in Europe are well aware of the value and necessity of DSM and DR as flexibility resources (He et al., 2013).

DSM is a particularly promising option in countries with strong demand-supply imbalances such as South Korea. In particular, the South Korean government realized that the supply-oriented policy cannot be sustainable and will reach the limit soon. In fact, these days the government is facing the difficulties to search for the available power plant sites for additional capacity due to the public’s low acceptability for the power installations^[2] and the enhancement of the environmental regulations. Therefore, it is almost impossible for the government to increase the electricity supply facilities without addressing those social issues first.

Traditionally, the South Korean government has placed focus on increasing electricity capacity rather than reducing or managing the electricity demand so far. However, recently, the government has changed its focus and perspective of the energy policy. Representing this change of focus, the market for DSM, especially for DR resources, was introduced on November 25, 2014 in South Korea—it is also called the ‘NegaWatt market’.^[3] To operate the market mechanism of DSM in an appropriate manner, South Korea needs to better understand its mechanism, advanced countries’ experiences, and know-how.

^[1] Apart from the supply and demand-side solutions, there are also other possible options, such as interconnection between power systems and regions, electricity storage, and so forth.

^[2] One of the examples is the case of the ‘Miryang Transmission Tower Construction Conflict’ in South Korea. It is the conflict between the local residents in Miryang and the state-owned [Korea Electric Power Corporation \(KEPCO\)](#) since 2002, and for the recent years (2012-2014) it has been much more serious drawing public attention.

^[3] There were a series of debates among some prominent economists whether or not ‘NegaWatts’ and ‘Megawatts’ are the same resources for electricity (Chao, 2011, p. 72).

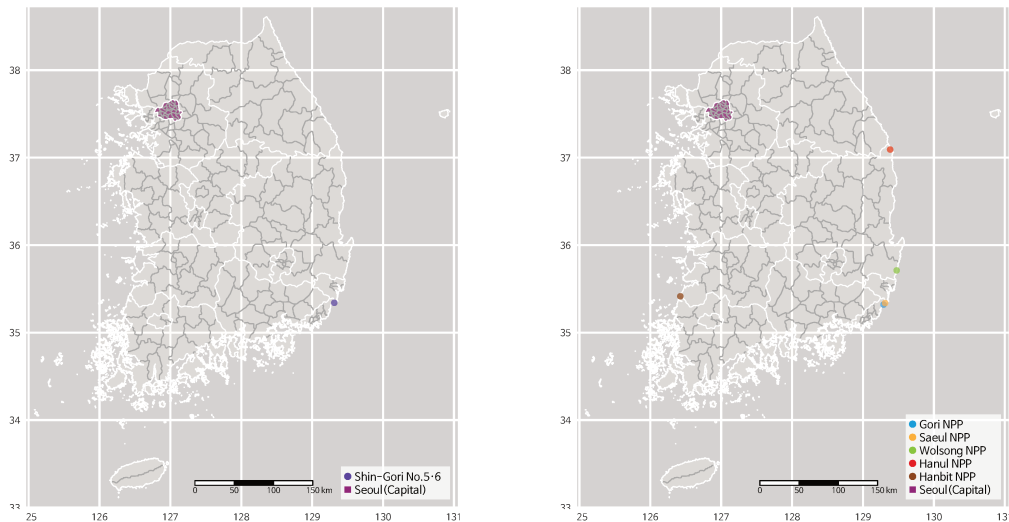


Figure 1.1: Locations of Shin-Gori Nuclear Reactors No. 5 & 6 Construction Site (left) and Other Existing Nuclear Power Plants (right) in South Korea

More recently, DR is getting more important in the context of the new South Korean government's energy policy, especially on nuclear, coal, and [Renewable Energy Sources \(RESs\)](#). President Moon was inaugurated on May 10, 2017. As he promised to phase out nuclear power during his election campaign for the nuclear-free era in South Korea, he let the 'Public Deliberation Committee on Shin-Gori Nuclear Reactors No. 5 & 6' decide whether or not to stop the construction of two nuclear reactors, Shin-Gori Nuclear Reactors No. 5 & 6 (Fig. 1.1). After the three-month public debate, on October 20, 2017 the committee announced the recommendations for the government—the resumption of the construction of the Shin-Kori Nuclear Reactors No. 5 & 6. Following the recommendations, the South Korean government announced the 'Energy Transition (nuclear phase-out) Roadmap' on October 24, 2017 [Ministry of Trade, Industry and Energy \(MOTIE\) \(2017b\)](#). In the energy transition (nuclear phase-out) roadmap, the government declared to drop the existing plans to build new nuclear power plants and not to extend the lifespan of nuclear reactors. It aims to decrease the share of nuclear energy to the total energy from 30.3% in 2017 to 23.9% by 2030. According to the roadmap, the number of the total reactors in operation will be 28 in 2022, 18 in 2031, and finally 14 in 2038.

President Moon also pledged to permanently shut down at least 10 aged, coal-fired power plants before his five-year term ends in order to reduce [Greenhouse Gas \(GHG\)](#) and fine dust emissions. To fill the energy gap resulting from both the nuclear energy and fossil fuel energy policies, the government plans to increase the share of the RESs from 7% now to 20% by 2030 [⁸ '8th Basic Plan for Electricity Supply and Demand (2017–2031)' published on December 29, 2017] ([Ministry of Trade, Industry and Energy, 2017a](#)). The installed capacity of the RESs as of 2017 amounts to 17.2 GW, and it should increase to 62.6–67.7 GW by 2030. This intermittent RESs need more flexibility and back-up, therefore it is expected that DR will play a more significant role in this context. The following Figure 1.2 summarizes the important events, acts, policies, and plans relevant to the DR in South Korea.



Figure 1.2: Timeline around Background and Introduction of South Korean DR Program

1.2 Theoretical Rationale for DR in Economics

Before conducting a detailed economic analysis of DR we need to understand how DR works and what the impacts of DR in the market will be both in the short term and long term by using the visual graphs. There were many studies explaining the mechanism of the market-based DSM and DR from the economic perspective. In the report of the U.S. Department of Energy (DOE) (2006), the short-term economic benefit of DR is well described (Figure 1.3) (U.S. Department of Energy (DOE), 2006, pp. 69–72)—which is the increase in the efficiency, and, in turn, the societal benefit, or the decrease in the dead-weight losses caused by the retail electricity rates based on average costs rather than the marginal supply costs. In other words, DR programs based on the marginal supply costs can increase the efficiency.

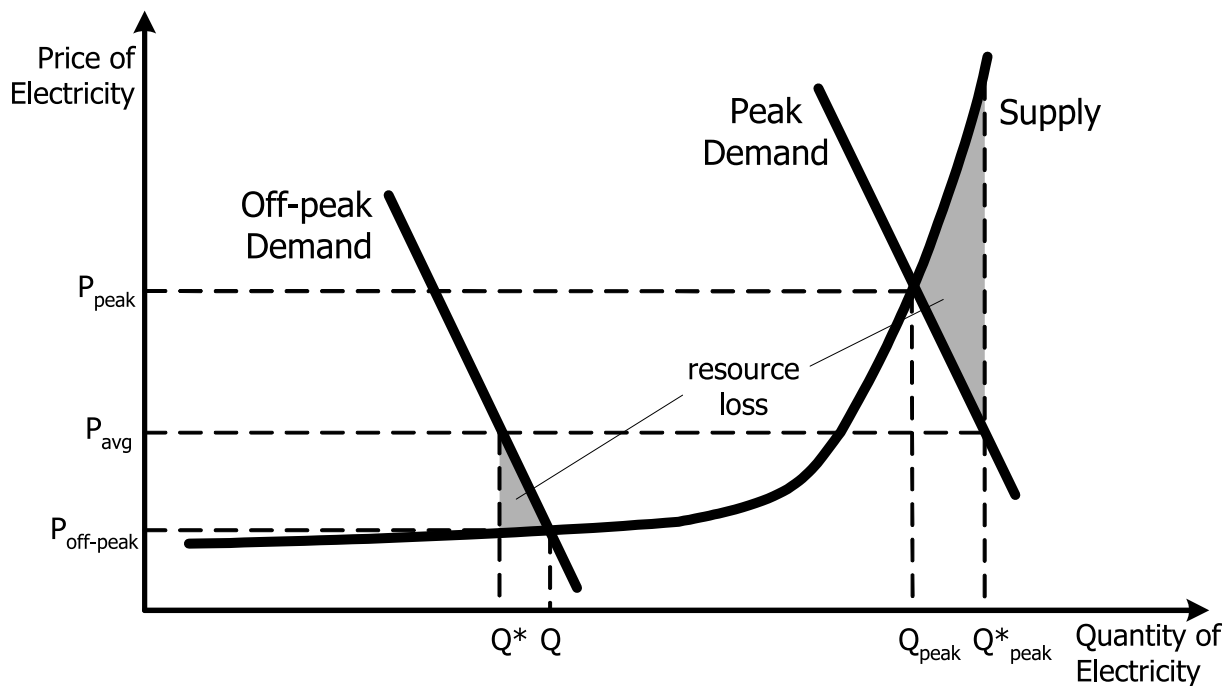


Figure 1.3: Inefficiencies of Average-Cost Pricing

Source: *Benefits of Demand Response in electricity markets and recommendations for achieving them* by U.S. Department of Energy (DOE), 2006, p. 70.

After that, it demonstrates how demand reductions by DR lower the price of electricity in the organized wholesale market and create the benefit by the price down (Figure 1.4) (U.S. Department of Energy (DOE), 2006, p. 73).

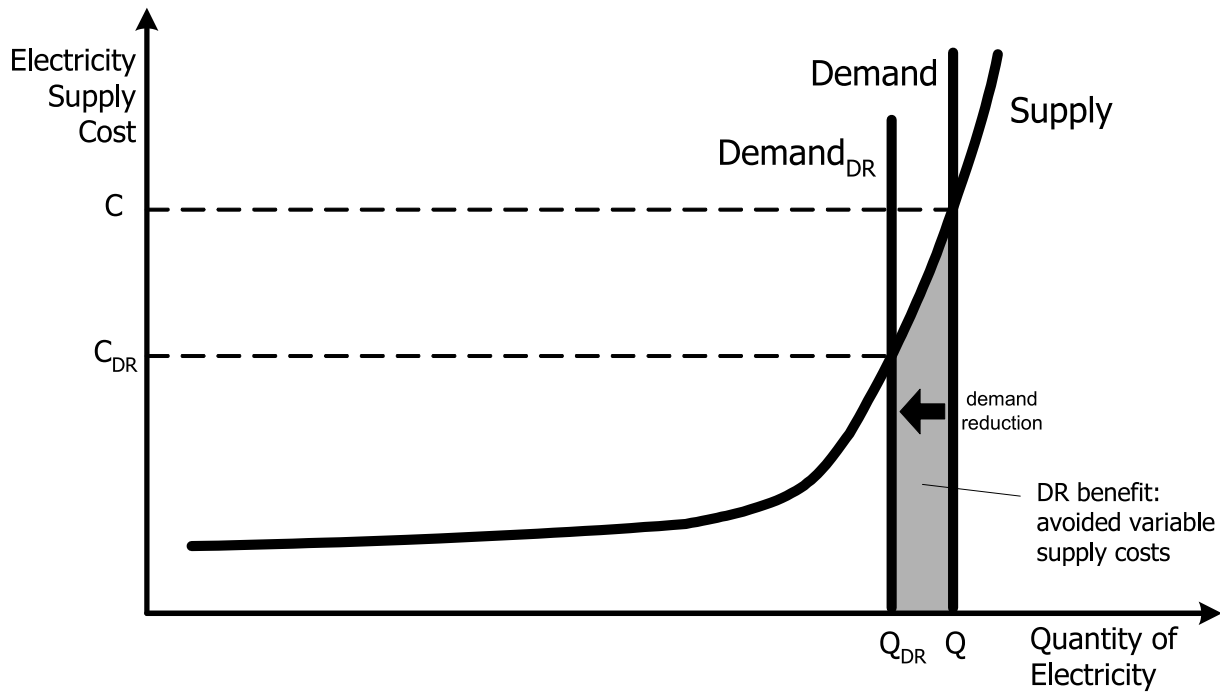


Figure 1.4: Impact of DR in Regions with Organized Wholesale Markets

Source: *Benefits of Demand Response in electricity markets and recommendations for achieving them* by U.S. Department of Energy (DOE), 2006, p. 72.

The same above-illustrated market impact of DR on the electricity price and social benefit is shown in the [International Energy Agency \(IEA\)](#) report (2003, p. 45) and a research paper (Figure 1.5) (Albadi and El-Saadany, 2008, p. 1991). However, in the two papers, they focused on the change in the elasticity of demand for electricity. With DR, the originally assumed inelastic demand curve turns into a little bit more elastic demand curve. As a result, it lowers the electricity price and improves the efficiency and social benefit in the entire market.

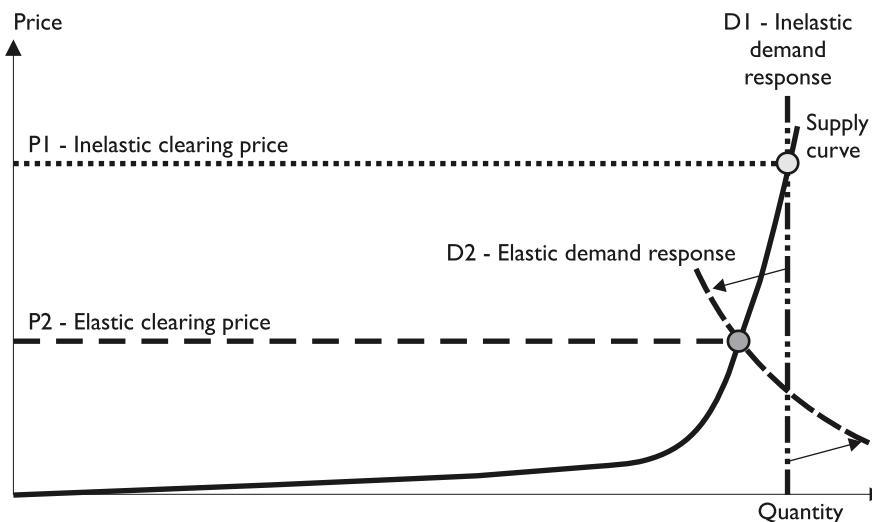


Figure 1.5: Impact of Demand Elasticity on Wholesale Price and Simplified Effect of DR on Electricity Market Prices

Source: *The Power to Choose: Demand Response in Liberalized Electricity Markets* by IEA, OECD, 2003, p. 45; "A summary of demand response in electricity markets", by Albadi and El-Saadany, 2008, *Electric Power Systems Research*, 78(11), p. 1991.

Contrary to the previous graphic analysis which placed emphasis on the impact of DR on the electricity demand curve, [Keppler \(2014a\)](#) gives us the visual explanation in which he focuses on the impact of DR on the electricity supply curve when demand-side resources are transacted at the wholesale market or capacity market. In addition, it is more in detail using the merit order curve and specific numbers helping us to understand more easily. Therefore, it is worthwhile to review his exposition. Looking at the following Figure 1.6, in brief, with the newly inserted supply by the electricity reduction (by DR or DSM, in yellow), it replaces the technology that is more expensive than the demand-side resources. Even though the quantity of the electricity consumption is the same ($Q_0 = Q_1$), the surplus of the consumer increases thanks to the decrease of the electricity price ($50\text{€} \rightarrow 40\text{€}$) by implementing DR. Moreover, from the perspective of the physical electricity producers, it is the reduction of their electricity demand ($Q_0 \rightarrow Q_1$). It causes a decrease in the surplus of the supplier (the dark orange area in the right graph). However, regarding the public's benefit, it is beneficial for the environment reducing the externality (external negative effects)—it cannot be expressed in the graph because the externality literally means 'out of the market' and 'out of the demand-supply curves'.

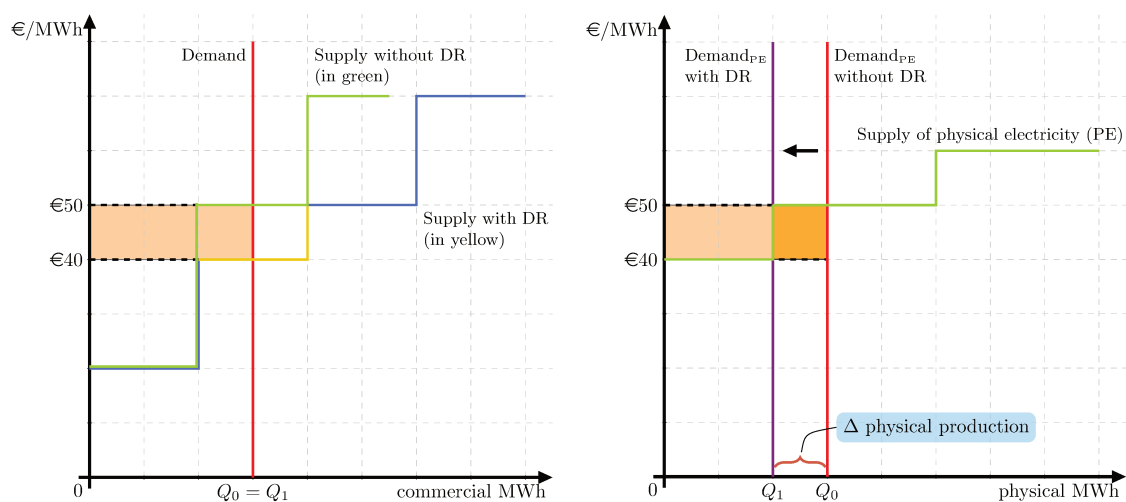


Figure 1.6: Graphical Analysis of the DR in terms of Commercial (left) and Physical (right) Electricity with Inelastic Demand and Merit Order Curve

Source: The author, Seungman LEE, has recreated the original figures in the following reference for translating it into English. *ANALYSE ÉCONOMIQUE DES BÉNÉFICES PRIVÉS ET PUBLICS EN TERMES DE CONSOMMATION ET PRODUCTION D'ÉNERGIE D'UN EFFACEMENT DANS LE CADRE DU NEBEF*, by [Keppler, 2014a](#).

1.3 Objectives and Scope of Research

The ultimate objective of the research is to provide DR program-related entities, especially DR system operators, with a decision-making framework based on the [Cost-Benefit Analyses \(CBAs\)](#) in which the optimization (linear programming) is utilized in order to represent the rationality of the DR participants, and to provide microeconomic explanations on DR participants' behaviors. In other words, we are going to figure out under what kind of conditions or circumstances a residential client participates in a DR program, how much loads does the client reduce or to which time slot does the client shift the electricity consumptions in order to minimize the costs. In addition, in order to take into consideration all the possible variations in terms of the key variables, the Monte Carlo simulation method will be utilized both for the Decision-making Analysis based on the CBA and its [Sensitivity Analyses \(SAs\)](#). Moreover, for the sake of convenience dealing with vast data and a number of repetitions of calculation, matrix algebra (linear algebra) is used as well as arithmetics. In the end, based on the CBAs, Decision-making Analyses, and SAs, we are going to draw policy implications for a better DR market design both for South Korea and France.

To that end, before CBAs, Decision-making Analyses, and SAs, we are going to establish experimental CBLs because [Customer Baseline Loads \(CBLs\)](#) are the most important and fundamental for the all following analyses. It is the first step and base to calculate the ultimate remuneration that can decrease or increase the motivation of DR participation. Considering these aspects of CBLs, it is expected that figuring out the impact of different CBL estimation methods on the DR markets by comparing two [Demand Response Mechanism \(DRM\)](#) of South Korea and France will provide us, to some extent, with the explanation for the different levels of the performance in South Korea and France. In addition, comparing and investigating the CBL estimation methods give us relatively more rooms to easily improve the DR market design and ameliorate the performance of French NEBEF mechanism than just trying to make a modification of given market conditions such as the [Cost-based Pool \(CBP\)](#) for South Korea or the price bidding system for France.

To analyze the different CBL estimation methods in South Korea and France, first of all, we are going to examine the currently used different CBL estimation methods in South Korea and France and assess them in terms of accuracy in order to find out the best one. It is expected that if one CBL estimation method performs better than others in one country, then, in a similar manner, it could significantly improve the performance of the DRM in another country.

The subject of this research is explicit (incentive-based) DR programs, not implicit (price-based) DR programs. In addition, the focus will be placed on the residential sector rather than the industrial or commercial sectors. The target countries for the comparative analyses are South Korea and France. The focus hour and date are the peak periods both for South Korea and France in 2016—at 5 p.m. and 6 p.m. (two time slots $t = 17h$ and $t = 18$) on Aug. 12, 2016, and at 7 p.m. (two time slots $t = 37$ and $t = 38$) on Jan. 18, 2016, respectively.

The following Table 1.1 summarizes the Sources of Datasets used in the Analyses of CBL Estimation Methods in Chapter 3 and CBAs in Chapter 4.

Table 1.1: Summary for the Sources of Datasets used in the Analyses of CBL Estimation Methods and CBAs

	South Korea	France
Loads	KPX	ENTSO-E
Information on residential clients: proportion, number	“Electricity Big Data Center” by KEPCO	RTE; CRE; Enedis
Data & Statistics about DR Programs	“Electric Power Market Statistics” by KPX	“PORTAIL CLIENTS” by RTE
SMP	KPX	EPEX
Tariff scheme (price)	KEPCO; “EPSIS” by KPX	IEA; EDF
Other information on electricity production & consumption	IEA; “PRIS” by IAEA	IEA; “PRIS” by IAEA

This dissertation is structured as follows (Fig. 1.7). In Chapter 1 the background and theoretical rationale of DR are explained, and the objectives and scope of the research are presented. Also, examining the previous studies on DSM and DR, many closely related concepts will be dealt as well as the advantages and challenges of DR. Before the analyses of the CBL estimation methods and CBA, brief case studies will be done for the U.S., France, and South Korea in Chapter 2. In Chapter 3 the experimental CBLs will be established, and analyses of the different CBL estimation methods will be conducted. Moreover, in order to guarantee the robustness of the analysis of the CBL estimation methods, the same analysis will be done with the different load profiles of the different seasons. In Chapter 4 the models for the CBA will be built using linear algebra, linear programming for optimization, and Monte Carlo simulations, and the methodology for the Decision-making analysis will be presented. After a thorough investigation of the results of the CBAs and Decision-making Analyses, the SAs will be done in order to cover different conditions for a given DR market design. Finally, in Chapter 5 taking into consideration the results and discussions, meaningful policy implications will be drawn for a better DR market design in terms of the accurate CBL estimation methods, and other key factors of the DRMs.

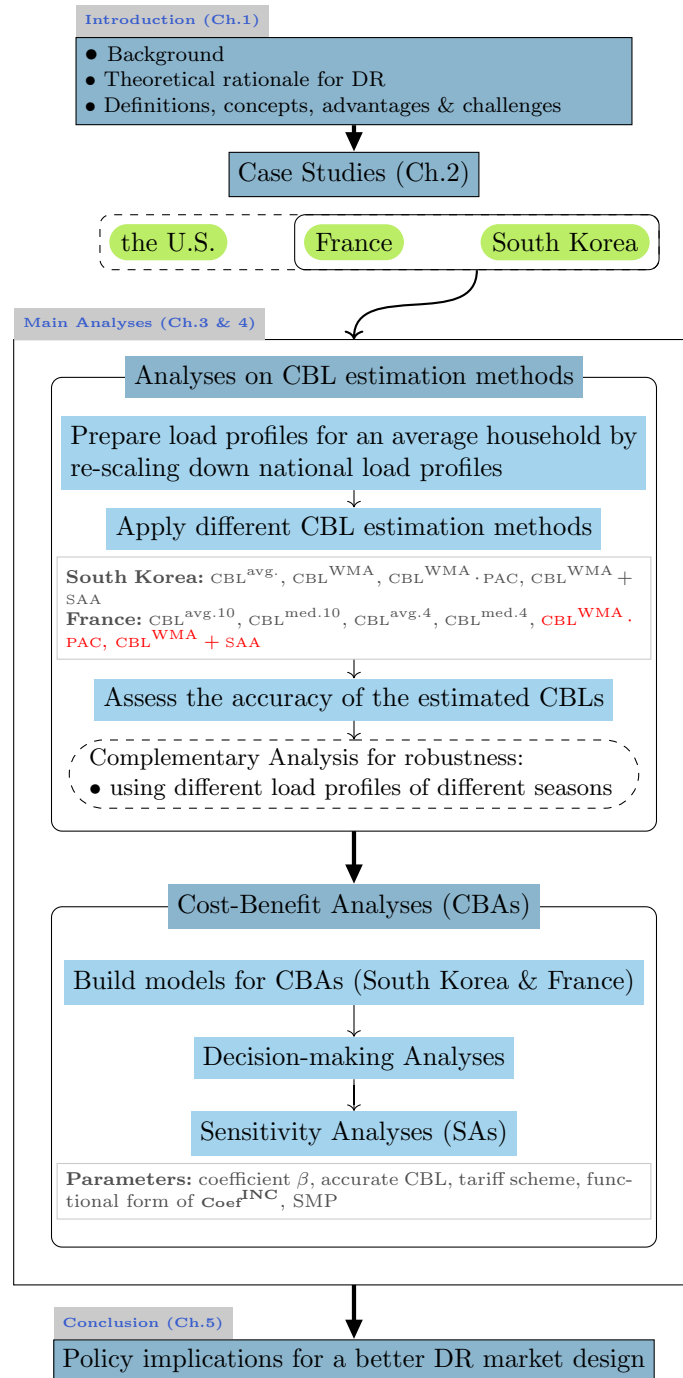


Figure 1.7: Flow of the Research

1.4 Literature Review

1.4.1 Definition of DSM and DR

The most frequently cited definition of DR^[4] is that of [Federal Energy Regulatory Commission \(FERC\)](#) ([Federal Energy Regulatory Commission, 2012](#)).^[5] As a number of DR programs are introduced by [Independent System Operators \(ISOs\)](#), [Regional Transmission Operators \(RTOs\)](#), and utilities, FERC and [North American Electric Reliability Corporation \(NERC\)](#) are categorizing and closely monitoring those DR programs.

The concept of DSM, simply, is the opposite to the supply-side management, which is focused on the expansion of electricity capacity installations. The term ‘Demand-side Management’ itself was first coined by Clark Gellings in 1984 ([Warren, 2014](#), p. 942), but as Warren found that the definition of DSM varies in what they include or exclude, there is no one widely accepted definition of DSM. According to his review, some people use almost the same definition of the SA and sometimes that of DR by others ([Warren, 2014](#), p. 942).

According to the [Charles River Associates](#) (2005, p. 6), DSM of electricity is “systematic utility and government activities designed to change the amount and/or timing of the customer’s use of electricity” for the collective benefit of the society, the utility and its customers. For [Bruninx et al.](#) (2013, p. 1), DSM is a (market) concept that actively uses options at demand- and supply-side to modify electricity demand to increase customer satisfaction and, at the same time, to produce desired changes in load shape of consumers. Moreover, [Warren](#) (2014, p. 943) argues that the definition of DSM should cover the recent objective and focus of the countries’ energy policies, such as the reduction in emissions of GHG and energy security.

DSM includes various categories of activities such as load management (usually it refers to DR),^[6] energy conservation (the energy efficiency improvements), fuel substitution, load building, and so forth—in [Figure 1.8](#), as indicated here, DSM is ‘higher and more comprehensive concept’ than DR. However, when I mention DSM in this dissertation, it means DSM which especially focuses and concerns on DR. In addition, we also notice the categorization of DSM in terms of the purpose of it. In this case, DSM may take two forms. First, it is emergency DSM to absorb a sudden fluctuation in demand which supply capacity and reserve power cannot meet. The second one is economical DSM which adjusts consumption to prevailing market conditions to avoid price hikes and steeply increased generating costs ([Clastres, 2011](#), p. 5403). When it comes to the measures (or tools) of DSM, there are financial incentives and time-varying pricing. DSM schemes based on financial incentives give customers payment for reducing consumption during periods of peak demand.

^[4] It is also called ‘Load Response’ by [PJM Interconnection \(PJM\)](#).

^[5] “Demand Response (DR): Changes in electric use by demand-side resources from their normal consumption patterns in response to changes in the price of electricity, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized”.

^[6] Load management includes load shedding, peak clipping, valley filling, and load shifting. [Kirschen](#) (2003, p. 522) points out the condition for the possible demand shifting that only if the consumer is able to store one of the factors of production, demand shifting is possible. Therefore, if we would like to enhance DR, we need a form of storage as well as some communication and control electronics.

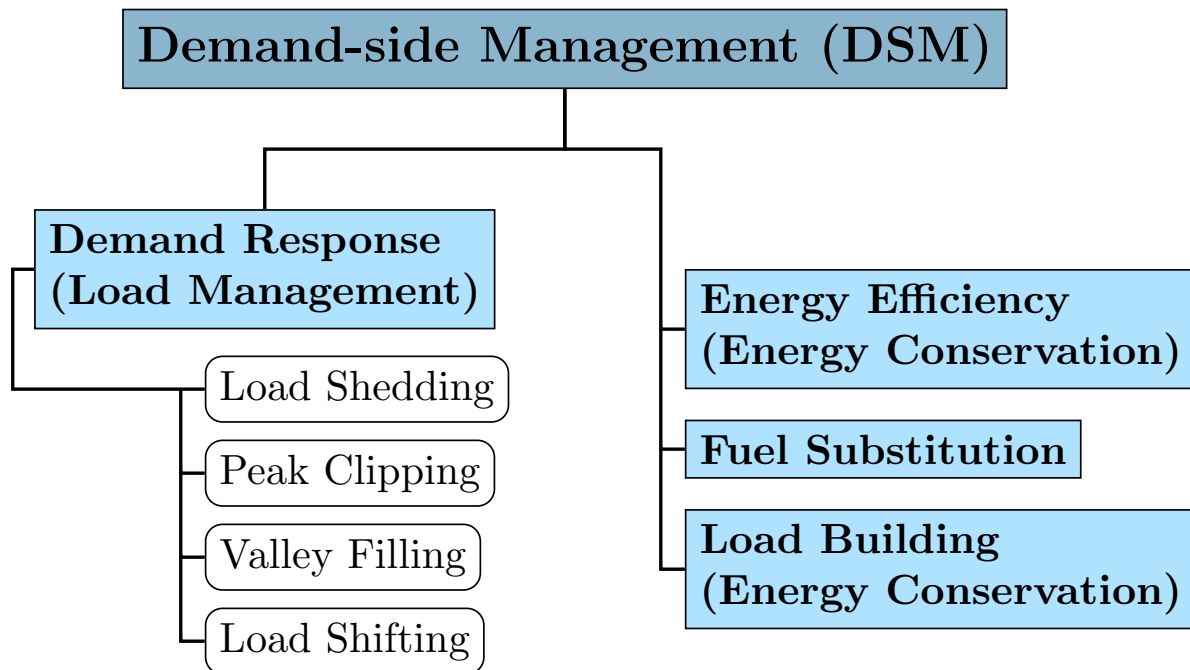


Figure 1.8: Categorization of DSM

Since the 1970's oil crisis, DSM has evolved significantly. In the 1980s, it was much more systematically utilized with the least-cost capacity expansion and [Integrated Resource Planning \(IRP\)](#) programs. In the 1990s, as the world paid more attention to the environment and climate change, DSM received more attention and support recognizing its potential benefits. Despite this significant evolution of DSM, it was not a success because the market participants lacked both the incentive and the means to respond. There were regulated retail prices, no advanced metering technologies, no real-time price information and policies focusing on supply-side resources (IEA, OECD, 2003, p. 10). However, recently with the unstable supply and high energy prices, many countries, such as the U.S., the UK, and so forth, highlighted the importance of DSM and introduced the market mechanism of DSM.

Among the categories of DSM, many scholars and practitioners have usually focused on load management and energy conservation (energy efficiency improvements). Usually, load management refers to DR,^[7] and demand-side resources refer to variable loads created as customers change their electricity consumption in response to price signals and other incentives (IEA, OECD, 2003, p. 9). In the capacity markets of many advanced countries like the U.S. and European countries, the demand-side resources are on the market as one of the capacity resources, which means demand-side resources have the same status competing with other capacity resources.

Among the several definitions of DR (Cappers et al., 2010, p. 1526; Svahnström, 2013, p. 3), it is common that it is possible for customers with DR to change their behavior or the patterns of electricity use in response to financial incentive or price of electricity. For example, according to Chao (2011, p. 71), 'Demand Response' refers to a customer's actions to alter its electricity demand by reducing or shifting consumption in response to the price of electricity or other market incentives. Also, it is noted that in the IEA report (2003, p. 17, 22), with DR programs, it could change the customer's price elasticity of demand for electricity. Furthermore, Chao defines 'demand-response capacity' as a consumer's right to sell unused electricity, relative to an established customer baseline, into wholesale electricity markets; and 'demand reduction' is the electricity sold when the demand-response capacity is deployed.

It is important and worthwhile pointing out clearly the difference between DR and [Energy Efficiency \(EE\)](#) improvement. DR is to adjust the pattern of the electricity consumption during a given time or period (day,

^[7] [Koliou et al. \(2013\)](#) use the term of 'Demand-side Response (DSR)', but it means the same with DR.

month, season, year) responding to the electricity price or incentives so that we can reduce the peak demand which is a part of electricity load curve. In contrast, for EE we need to change electric equipment and electrical appliances of low energy efficiency with ones of high energy efficiency. With electric equipment and electrical appliances of higher energy efficiency, we can consume less electricity (energy) for the same work or objective. To that end, it needs lots of investment to change the hardware. Once we achieve energy efficiency, we can reduce the overall electricity demand for the entire long term period of the electricity load curve (if there is no 'rebound effect').^[8] He et al. (2013, p. 4) highlight one of the differences that with EE we maintain the same level of end-use services using less energy, whereas DR could consume more electricity than as usual when it is needed, requested or possible.

In addition to the distinction between DR and EE, we need to be clear with the term of 'Active Demand Response (ADR)' which is widely used recently. In what sense did scholars add 'active' in front of DR? In the paper of He et al. (2013, p. 4), they exclude any DR programs which were mandatory or resulted from the customers' behavior without compensation. In other words, they exclude the Direct Load Control (DLC) which does not accompany with any financial incentive or payment. Bruninx et al. (2013, p. 1) also use the term of ADR, but it seems that, in the paper, ADR just refers to the short-term load shifting.

As we recognized that the main two momentums (additional financial incentives and price) of the customers' behavioral change in the electricity demand and electricity usage patterns, when it comes to DR systems, it is mainly divided into two systems—in Figure 1.9, incentive-based DR systems^[9] and price-based DR systems [Time-of-Use (ToU), Critical Peak-Pricing (CPP) or Real-time Pricing (RTP) system].^[10] In terms of incentive-based DR systems, it could include, for example, 2 month-ahead demand control system, 1~5 days ahead demand control system, and demand bidding system, which is currently implemented in South Korea (Won and Song, 2013, p. 1296).

^[8] The term of 'rebound effect' means that as a result of the improvement in energy efficiency, the de facto relatively lower price of electricity encourages consumers to spend more electricity, that is more demand for electricity, than before. Please, refer to Birol and Keppler (2000).

^[9] The Incentive-based Programs (IBPs) are further divided into classical programs and market-based programs. The classical IBPs include the DLC programs and Interruptible/Curtailable Load programs. For the market-based IBPs, it includes the Emergency DR programs, Demand Bidding, Capacity Market, and the Ancillary services market (Albadi and El-Saadany, 2008, p. 1990, Figure 1).

^[10] Price-based Programs (PBPs) are also called time-based DR programs. Among them, RTP fully reflects the operational costs of a marginal plant, and it is expected to carry the highest incentives (Clastres, 2011, p. 5402). Therefore, Koliou et al. (2013, p. 2) believe that other rate structures, such as ToU and CPP, are a way to get closer to RTP, and that the ultimate objective is to introduce RTP in the market. In addition to ToU, CPP, and RTP systems, there are also Extreme Day Pricing (EDP) and Extreme Day Critical Peak-Pricing (ED-CPP) (Albadi and El-Saadany, 2008, p. 1990, Figure 1). CPP is a hybrid of ToU and RTP. One of the examples of CPP is found in France. The EDF's Tempo tariff program, which is the world's largest CPP program, is in operation—it was 10 million customers of the Tempo tariff (IEA, OECD, 2003, p. 33).

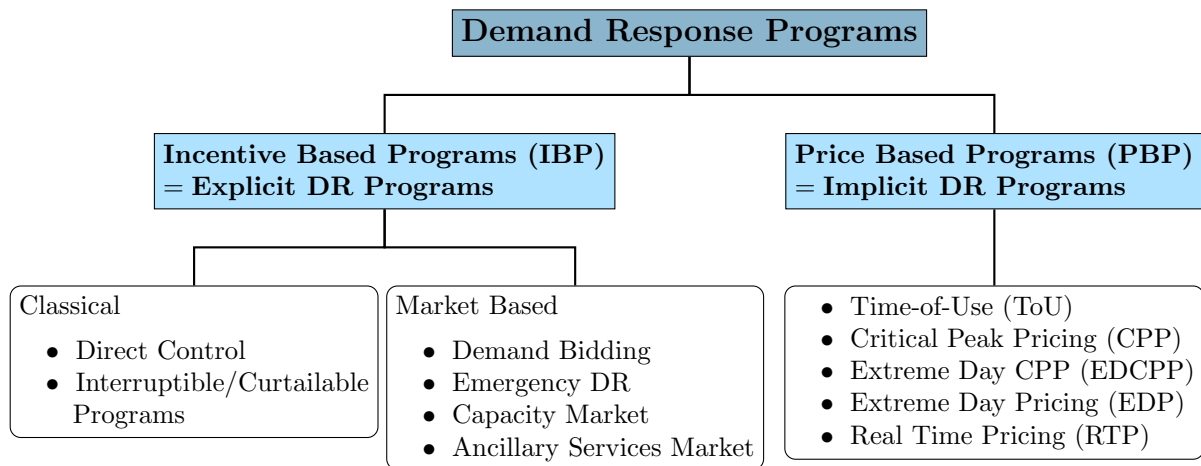


Figure 1.9: Categorization of DR Programs

Source: With some modifications of the original figure of “A summary of demand response in electricity markets”, by [Albadi and El-Saadany, 2008](#), *Electric Power Systems Research*, 78(11), p. 1990 (changed the design maintaining the original contents).

Similarly, but slightly differently, in the report of the [Cappers et al. \(2013, pp. 2–6\)](#), the researchers categorize the treatments into two: event-based treatments and non-event-based treatments. The event-based treatments include CPP, CPR (critical peak rebate, or [Peak Time Rebate \(PTR\)](#)), DLC, and the non-event-based treatments include time-based rates, information and feedback about usage behavior, or control devices that facilitate easier changes in usage behavior, in-home displays (IHDs), programmable communicating thermostat (PCTs), feedback mechanisms, educational efforts, and combinations of these. However, this distinction is not so clear because there are some electric pricing structures that have characteristics of both event-based and non-event-based treatments, such as RTP or [Variable Peak Pricing \(VPP\)](#), and they call it ‘hybrid’ treatments.

Those DR systems or programs are not totally exclusive to each other. Rather, they could complement and accompany with other programs. For instance, [Bruninx et al. \(2013, p. 1\)](#) point out that ADR can be facilitated by dispatchable load programs (DLC, curtailable load, demand bidding) and/or price-based programs, such as ToU, CPP, and RTP, because each one has its own opportunities and drawbacks. [Koliou et al. \(2013, p. 2\)](#) share the same idea with Bruninx et al. mentioning that even though they have categorized DR into two—controllable demand-side response and price-based demand-side response, but their design and implementation in reality are not mutually exclusive, so the variations and combinations of those DR structures are possible.

In addition, it is also possible to categorize DR programs in terms of the purpose of the DR programs. ‘Economic demand response resources’ can be utilized at the wholesale markets in order to decrease the price competing with the other generation-side resources. ‘Reliability demand response resources’ can be utilized in order to ensure the system reliability.

Moreover, in terms of the types of their services, DR can be categorized into four: 1) energy, 2) capacity, 3) reserve, and 4) regulation (Fig. 1.10) ([NERC, 2013, p. 9](#)).

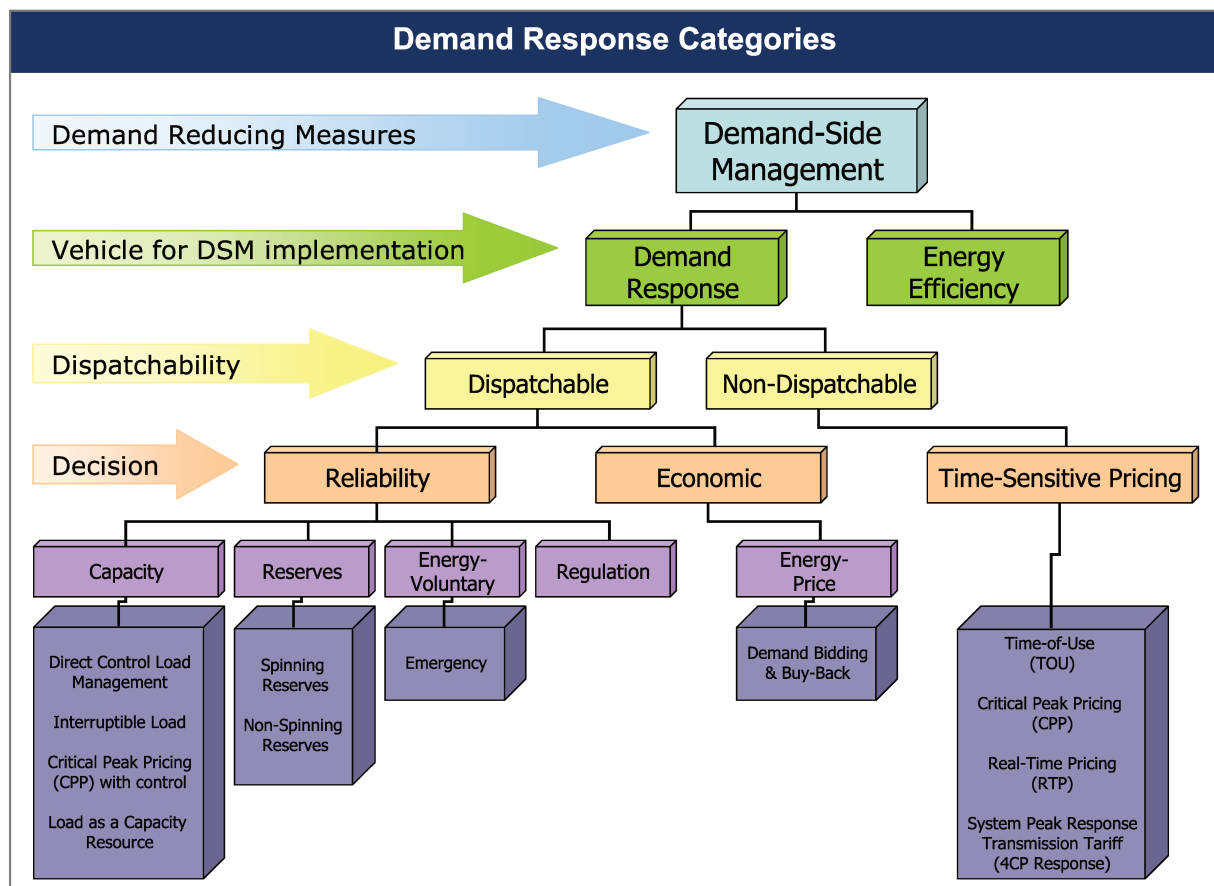


Figure 1.10: Categorization of DR by NERC

Source: NERC, 2013, p. 9.

At the market for demand-side resources, there are several entities [implementers of DR in (Warren, 2014, p. 943)] to participate in, such as utilities, RTO/ISO/[Transmission System Operator \(TSO\)](#)/[Distribution System Operator \(DSO\)](#)—those are network operators, customers, [Load Aggregator \(LA\)](#) (or intermediaries for contracts between customers and RTO/ISO/DSOs), and governments. Utilities provide customers with financial incentives for DR. An RTO/ISO has a role to maintain the reliability of the electricity system in which the electricity demand is rapidly increasing and to control the signal of the electricity price. Doing so, it promotes a new investment of supply capacity or demand-side resources. It also establishes a plan of electricity for its region and tries to reduce the costs for the electricity transmission of intra-region or inter-regions.

An ISO makes good use of LAs in order to increase the effect of demand reduction and to manage the risk from the numerous small customers—also, an ISO reduces its operational costs (Gkatzikis et al., 2013, p. 1247). Because there are not only risks and responsibilities in contracts (or interaction) between customers and utilities/RTO/ISO/TSO/DSOs but also a comprehensive costs and benefits, the role of LAs and their support for the customers is substantially important to achieve ADR (He et al., 2013, p. 5). In fact, LAs are new entities in the electricity market.^[11] They are responsible for the installation of the communication and control devices at end-user premises (Gkatzikis et al., 2013, p. 1247). Their objective is, of course, as enterprises, to maximize their profit, that is, the income from the operator minus (-) the monetary compensation to the residential customers. The study by Gkatzikis et al. (2013) is a valuable one that provided us with a better understanding of the importance of the aggregators' role as intermediaries between the utilities and a number of residential clients in a 'hierarchical market structure (model)'.

^[11] For examples, as LAs, there are *EnerNOC* and *C-Power* in the U.S., *Energy Pool* (France), *Entelios* (Germany) in Europe (Smart Energy Demand Coalition, 2011). Please, refer to Figure 1.11 which indicates the DR aggregators in Europe and the entities who plays as aggregators.

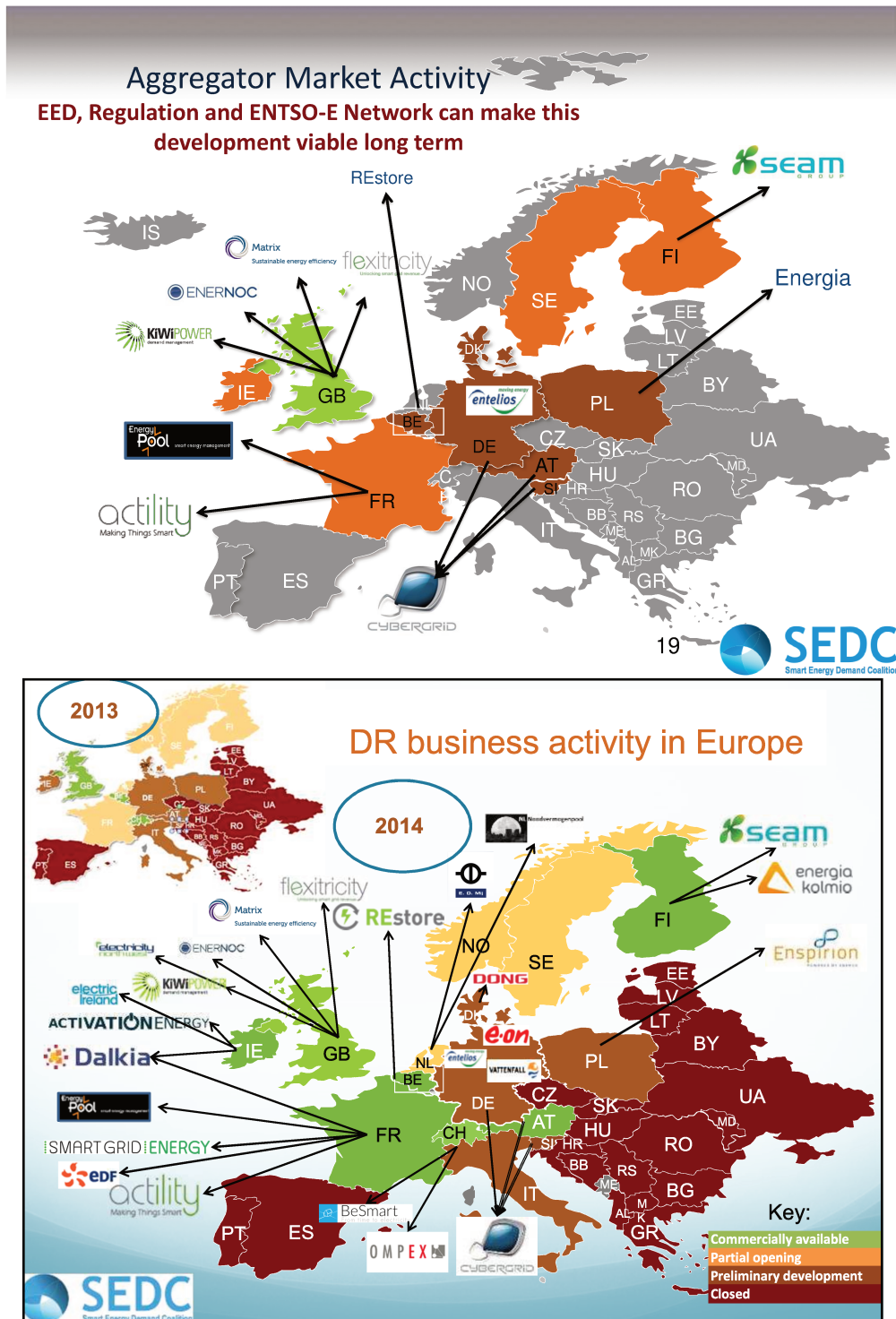


Figure 1.11: Entities Play as Load Aggregators in Europe (previously and in 2014)

Source: Demand Response development Stromback, nd, SEDC (Smart Energy Demand Coalition), p. 19; "Demand Response: the value of non-use". by Stromback, 2014, SEDC (Smart Energy Demand Coalition), In BERLIN ENERGY FORUM, Berlin, 10-11 February 2014, p. 3.

In terms of customers, first, we can divide them into two: a few large size industrial consumers (large general-service customers), and residential (households) and SMEs (small and medium enterprises) consumers (He et al., 2013, p. 4). Or we could categorize them into three: industrial, commercial^[12] and residential cus-

^[12] In the report of Smart Energy Demand Coalition (2014, p. 2), it defined the meaning of 'commercial' as "all

tomers. The application of various DR programs and the electricity tariff systems depends on the classes of customers. For instance, peak-load management programs (or CPP) are available to industrial and commercial classes of customers^[13], and usually, ToU rates are available for households with electric heating^[14] (Strbac, 2008, p. 4424). Gkatzikis et al. (2013, p. 1247) point out that the application of DR to the industrial customers has been successful, but there would be challenges when we apply the same existing DR to the residential sector (home users). The active participation of customers is essential and is one of the prerequisites for the successful DR (Svahnström, 2013). Without proactive customers' participation and remarkable change in consumers' behavior, we cannot imagine the satisfactory management of DSM and DR programs.

In the paper of Warren (2014, p. 943), he demonstrates the implementers of DR in a figure, and he puts governments in it. He also highlights the critical role of the government's regulatory support for DSM and DR.

1.4.2 Relations between DSM, DR, Smart Grid, Renewable Energy, Climate Change, and Capacity Market

DSM, DR, and Smart Grid (SG) have close relations, and sometimes it is difficult to think them separately (Svahnström, 2013). Sometimes some scholars just take SG as a synonym for DSM and DR because it is difficult to figure out a precise difference between them. In fact, we can find DR in the definition of SG by the U.S. DOE (Clastres, 2011, p. 5400).^[15] The reason why those three concepts are similar is that they have smart meters^[16] or the smart metering system in common. Smart meters are the most important technology which enables DR operating and the NegaWatt Market (Warren, 2014, p. 947; Covrig et al., 2014, pp. 90–96).

Likewise, according to Lee et al. (2010, p. 323) DR belongs to the layer of application of three layers—physical power layer, data transport and control layer, and application layer—which are constituting SG. In addition, IEA, OECD (2011) points out that SG is expected to be an important facilitator for increased DR.

For the link between DSM, DR, and renewable energy, we can think of the current situation in Europe. For many countries, especially Germany, France, the UK, and Spain, the share of renewable energy in their energy mix has starkly increased in accordance with the '20-20-20 targets'.^[17] As a result, the predictability has decreased, and the uncertainty has increased—with the nature of RESs that is intermittent.^[18] Moreover,

buildings and businesses which are not directly industrial or residential; in other words, municipal buildings, SMEs, businesses such as hotels, office spaces, etc”.

^[13] This event-based tariff scheme has been adopted by the California ISO to reduce the peak-loads during hot summer days from noon to 18:00 when the air-conditioning system is fully employed (O'Connell et al., 2014, p. 687).

^[14] The most famous example of ToU was the EDF's Tempo tariff in France, which targeted on residential customers and was peak and off-peak rates (Clastres, 2011, p. 5402).

^[15] The definition of SG: “self-healing from power disturbance events; enabling active participation by consumers in demand response”; operating resiliently against physical and cyber attack; providing power quality for 21st century needs; accommodating all generation and storage options; enabling new products, services, and markets; optimizing assets and operating efficiently”.

^[16] Smart meters are advanced energy meters that can read real-time energy consumption information, and that allow bidirectional communication of data to enable information to be collected regarding any electricity fed back to the grid from customer premises through micro-generation (Warren, 2014, p. 947).

^[17] Known as the '20-20-20 targets', it is the EU's ambitious climate and energy targets for 2020. It is found in the '2020 Energy and Climate Package' in 2009 (the 3rd package). The three targets are: 1) 20% reduction in EU GHG emissions in terms of the level in 1990, 2) increasing the share of the RESs in the EU countries' energy mix up to 20%, 3) the improvement of 20% in the EU's energy efficiency.

^[18] The traditional power plants based on fossil fuels are dispatchable, which means they are predictable and stable in terms of power generation, and they can adjust the output so that they can respond to a call and then they are employed whenever it is needed. On the contrary, the RESs, such as wind power, photovoltaic, are intermittent, which means the power generation output from them is not continuously available and fluctuating, heavily depending on the weather conditions like the speed of the wind and the intensity of sunlight. Therefore, it is said that the 'capacity credit' and 'capacity factor' of the traditional power plants are higher than those of the RESs. As a result, the RESs need backup generation capacity when the output from the RESs is low.

Europe is in the middle of the energy transition from the traditional and centralized generation mix to a decentralized and distributed one. These days it is decentralized and distributed, so it is difficult to ensure the flexibility from the supply- or generation-side in order to balance supply with demand. In this situation, it is needed to seek flexibility from the demand-side, that is, DSM and DR (He et al., 2013, p. 1). Bruninx et al. (2013) also point out the same situation with increasing renewable energy and the alternative role of DSM and DR. In that sense, DR is a promising measure to ensure the power system flexibility and consequently facilitate the integration of RESs to the existing power system (O'Connell et al., 2014, 688).

For the issues of climate change and CO₂ emissions, DR plays a role similar to that of RESs. As DR programs are implemented, it reduces the electricity demand during the peak period when usually the fossil fuel-based power plants are employed for the peak loads—also, DR could reduce the total electricity consumption and reduce the total power generation. As a consequence, DR can reduce the amount of CO₂ emissions which could have been emitted for the peak loads. It is the benefits for the entire society—the increase in the net welfare of society.

The concept of Capacity Market is closely related to DR. In the U.S., the UK, and France, demand-side resources are traded in their capacity markets in which demand-side resources are treated in the same way with generation capacity. Through these capacity markets, demand-side resources and consumers relying on LAs can participate in electricity markets, and they could receive the real market value of participating in DR programs (Smart Energy Demand Coalition, 2011, p. 8).

1.4.3 Advantages and Challenges of DR

1.4.3.1 Advantages of DR

There have been a number of researches on the general benefits and challenges of DR. Bruninx et al. (2013, p. 1) enumerated a variety of benefits of correctly applied DSM, such as “a reduced electricity generation margin, higher operational efficiencies in production, transmission and distribution, more effective investments, lower price volatility, lower electricity costs, and the possibility to manage highly intermittent renewables”. Jiang et al. (2015) also pointed out that DSM has the potential to lower market prices, reduce price volatility, improve customer options and increase the elasticity from the wholesale to the retail market.

Among several benefits, firstly we can approach from three dimensions:^[19] increased efficiency, enhanced energy security, and deterred or more efficient investment. First of all, it can increase the efficiency of the entire power system and market. Shifting the peak load to the hours of off-peak (trough or valley), it can improve the efficiency of the usage of generation, transmission and distribution resources (facilities). With regard to the electricity market, Kirschen (2003, p. 520) points out that more active participation of the consumers in DSM would render electricity markets more efficient and more competitive, and it would lead to a more optimal allocation of economic resources. This increased efficiency leads to the decreased price of electricity. Some case studies have shown that with a 5% DR capability we can decrease the wholesale electricity prices by up to 50%. Also, the introduction of DR in the U.S. led to the savings for the electricity customers between \$10 billion to \$15 billion per year (IEA, OECD, 2003, p. 11).

Secondly, active participation in DR increases the security of the electricity system—in other words, it means the increase in the power system flexibility. It is the benefit to the system operator who can increase the number of options available for maintaining its security. With more options available to address the security

^[19] More in detail, Bradley et al. (2013, p. 314) summarize in the eight core benefits of DR. Benefits from “1) relative and absolute reductions in electricity demand, 2) short run marginal cost savings from using DR to shift peak demand, 3) displacing new plant investment from using DR to shift peak demand, 4) providing reserve for emergencies/unforeseen events, 5) providing standby reserve and balancing for wind, 6) benefits of DR to distributed power systems, 7) reduced transmission network investment by reducing congestion of the network and avoiding transmission network re-enforcement, 8) using DR to improve distribution network investment efficiency and reduce losses”.

issue, the system operator can reduce the dependency on the power generation-side, and this helps to reduce the market power of generating companies. Therefore, the increase in the security of the electricity supply has a value that is shared by all consumers (Kirschen, 2003, p. 526).

The benefits of DR for the long term are related to investments for generation capacity and networks (He et al., 2013, p. 1). The U.S. Department of Energy (DOE) (2006, p. 74) considers the benefit as the long-term market impacts of DR by reducing the system peak demand. It is appreciated that DR resources are more cost-effective than power production in terms of power reserve (Svahnström, 2013, p. 3; Warren, 2014, p. 942). Because an emergency situation infrequently happens, building new power plants as backup power and maintaining them are much more costly. In that sense, Svahnström (2013) mentions the potential of DR to reduce the need for the current fossil fuel-based power reserve and, in turn, to facilitate an increased share of RESs.

For example, Strbac (2008, p. 4419) argues that considering the low utilization of generation and networks in the UK (about 50%), shifting loads by DR would reduce the need for generation capacity and increase the utilization of generating plants and hence increase the efficiency of the investment in generation capacity. In other words, because the expected frequency for the high magnitude of shortages is rare, DR is more efficient than increasing the capacity installations. Also, Strbac adds that DR could provide consumers with the right of choice regarding the usage of electricity and prevent 'cross-subsidies'^[20] between two types of consumers (Strbac, 2008, p. 4421).

In reality, we could easily confirm the aforementioned benefits of DR. The paper written by Cappers et al. (2010, p. 1526) summarizes the existing contribution of DR resources in the U.S. electric power markets. Also, the report prepared by the Smart Energy Demand Coalition (SEDC) (2014, p. 2) focuses on the economic and monetary gains, which is visible and concrete benefit to consumers, from DR programs mentioning that in 2013, in the U.S., businesses and homeowners earned over \$2.2 billion in revenues from DR avoiding investment in grid infrastructure and power plants.

In sum, it increases the efficiency of the electric system and substantially reduces the need for investment in generation capacity by shifting peak load away from peak hours. Finally, it increases the energy security and encourages market competition around consumer service offerings (Smart Energy Demand Coalition, 2014, p. 2).

1.4.3.2 Challenges for DR

Despite those several advantages of DR, in order to induce the active participation of clients and to finally achieve the benefits of DR, there are still several challenges and obstacles to overcome. In the past, one of the main barriers to DSM was the technical problem. There were not fully advanced Information and Communication Technologies (ICTs) to apply DSM to the electricity market (Strbac, 2008, p. 4425). Chao (2011, p. 70) also pointed out the lack of Advanced Metering Infrastructure (AMI) as one of the two main barriers to introducing the price-responsive demand as well as the widespread practice of fixed uniform retail rates.^[21]

Regarding the lack of AMI, thanks to the recent development of technology, at this moment, it is not the main concern anymore. The required AMI has been already developed, and in many regions, its usage is underway (O'Connell et al., 2014, p. 687). For example, Figure 1.12, in the U.S., as of the end of 2016, almost half

^[20] Chao (2011, pp. 70–71) also mentions that a fixed uniform retail rate causes the problem of the 'cross-subsidies' that distort incentives. For instance, customers who consume most of their energy during low marginal cost, i.e. off-peak periods, are charged the same price as those who consume most of their energy during high marginal cost, i.e. peak periods. In practical terms, this means customers who consume electricity during off-peak periods subsidize peak users. As a result, a uniform retail rate encourages excessive electricity consumption during peak periods when real-time wholesale prices are higher than the retail rate, providing a perverse incentive for peak users to prefer the fixed retail rate to dynamic pricing (Crew and Kleindorfer, 1978).

^[21] Here, a fixed uniform retail rate means a regulated tariff (He et al., 2013, p. 5).

of all U.S. electricity customers had smart meters (U.S. Energy Information Administration (EIA), 2017).^[22] In more detail, there were about 150 million electricity customers in the U.S., and among them, 71 million electricity customers had AMI smart meters. Therefore, the penetration rate of smart meter was about 47% as of 2016 in the U.S—as can be seen in Figure 1.12 it is already more 50% in 2017.

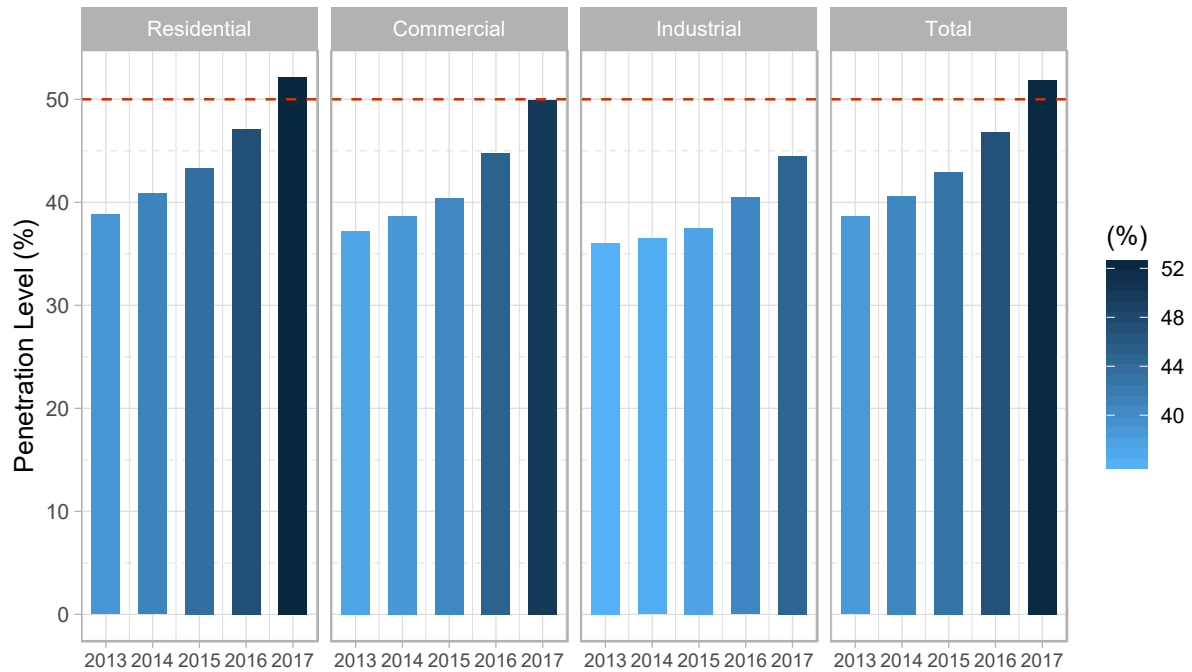


Figure 1.12: Smart electricity meter installations (2013-2017)

Source: *Annual Electric Power Industry Report*, by U.S. Energy Information Administration (EIA), [On-line], Available: https://www.eia.gov/electricity/annual/html/epa_10_10.html

Like the numbers of residential customer are different state to state in the U.S. (Fig. 1.13),^[23] the penetration rates of the AMI by state are also quite different state to state (Fig. 1.14).^[24]

^[22] For *Electric Power Annual Report and Data Tables*: [On-line], Available: <https://www.eia.gov/electricity/annual/>, and for **detailed data files**: [On-line], Available: <https://www.eia.gov/electricity/data/eia861/>

^[23] Please, refer to other figures for the number of commercial (Fig. A.1) and industrial (Fig. A.3) customers by state, 2016 in the U.S. in [Appendix A: Supplementary Figures & Tables](#) of this dissertation.

^[24] Please, refer to other figures of the AMI penetration rate for commercial (Fig. A.2) and industrial sector (Fig. A.4) by state, 2016 in the U.S. in [Appendix A: Supplementary Figures & Tables](#) of this dissertation.

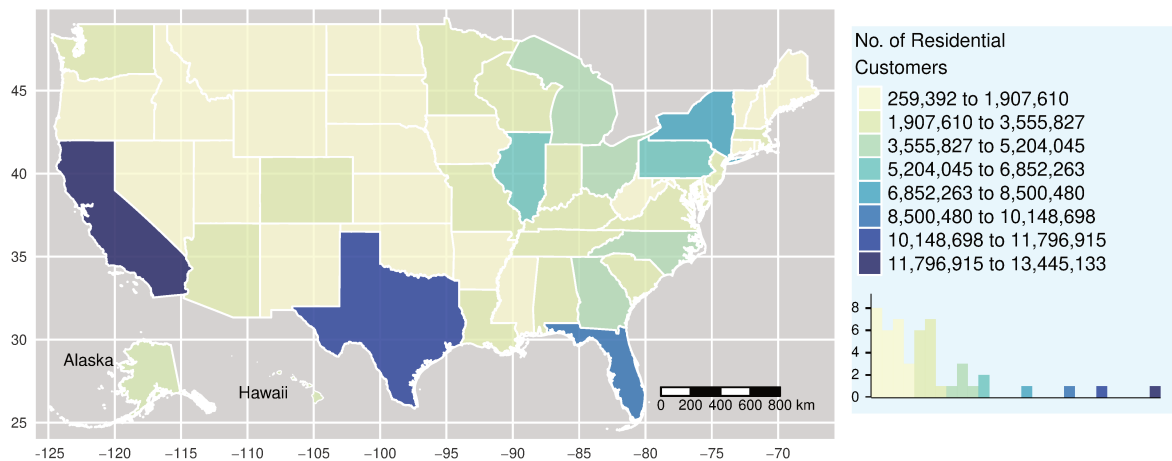


Figure 1.13: The Number of Residential Customers by State, 2016 in the U.S.

Source: *Annual Electric Power Industry Report*, by U.S. Energy Information Administration.; “Electric power sales, revenue, and energy efficiency Form EIA-861 detailed data files”, U.S. Energy Information Administration, [On-line], Available: <https://www.eia.gov/electricity/data/eia861/>

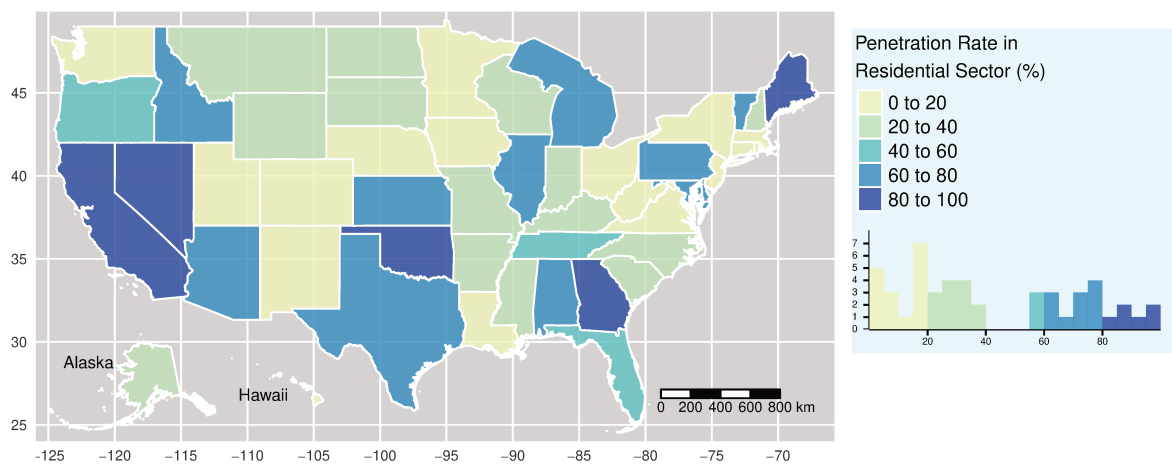


Figure 1.14: Residential Smart Meter Adoption Rates by State, 2016 in the U.S.

Source: *Annual Electric Power Industry Report*, by U.S. Energy Information Administration.; “Electric power sales, revenue, and energy efficiency Form EIA-861 detailed data files”, U.S. Energy Information Administration, [On-line], Available: <https://www.eia.gov/electricity/data/eia861/>

Table 1.2: The Top 10 States in terms of the Number of Customers and AMI Penetration Rate in the Residential Sector

Rank	State	No. of Customers	State	AMI Penetration Rate (%)
1	California	13,445,133	District of Columbia	99.6
2	Texas	10,521,732	Nevada	95.3
3	Florida	9,149,214	Maine	91.7
4	New York	7,118,901	Georgia	89.2
5	Pennsylvania	5,335,555	Oklahoma	85.0
6	Illinois	5,231,541	California	82.7
7	Ohio	4,911,597	Michigan	79.3
8	North Carolina	4,423,532	Vermont	78.4
9	Michigan	4,311,008	Arizona	76.6
10	Georgia	4,240,421	Texas	75.9

Source: *Annual Electric Power Industry Report*, by U.S. Energy Information Administration.; "Electric power sales, revenue, and energy efficiency Form EIA-861 detailed data files", U.S. Energy Information Administration, [On-line], Available: <https://www.eia.gov/electricity/data/eia861/>

Instead, the remaining technological problem is the establishment of the standards and protocols, and the compatibility of the hardware. On top of the technical issue, O'Connell et al. (2014) point out that the real challenge is to develop accurate control and well-designed market frameworks. Moreover, the significant investment for the information, communication and monitoring infrastructure is one of the challenges.

Furthermore, a serious concern is the lack of experience with DR, especially at the level of residential loads (O'Connell et al., 2014, p. 688). So far there have been many experiences of the load control programs with large industrial and commercial customers, but there were not so many DR programs for households because it was difficult to manage and there was no platform to access for residential consumers to electricity markets. It is true that it lacks policy measures supporting DR, and the greatest barrier for establishing a policy to support the development of DR was the uncertainty on the true benefits and costs of such DR programs for residential clients (O'Connell et al., 2014, p. 688). Recognizing the lack of CBA for this infrastructure and programs, and the lack of methodology for the quantification of the costs and benefits, we will discuss this issue more in detail in Chapter 4.

Lastly, the distribution of the costs and benefits that come from the operation of DR among the participants also remains as an issue (He et al., 2013, pp. 2–3). As we have looked at the various entities and actors in the electricity market in terms of DR, there are two different implementers (players or actors): the incumbents, such as utilities and ISO/RTO/TSO/DSOs, on the one hand, and new entrants, such as independent LAs on the other hand. Therefore, the questions that who will take the costs—even though ultimately it will pass through to end-users—and how they could divide the value created by DR are still thorny issues.

To overcome the challenges we can highlight the critical factors for the success of DR. In the report written by He et al. (2013), they use a consumer-centered approach for the full activation of DR and highlight the importance of contracts^[25] which reflect a range of different consumer categories. They place an emphasis on the change in mindset in which we should regard consumers as a source of flexibility in order to achieve the ADR. Thanks to their report it was a good opportunity to reconsider the importance and the role of consumers. They explained very well what kind of efforts we need to make to transform the consumers into very

^[25] A contract in which the retailers ask consumers to reduce their loads during a peak demand period can give the flexibility to customers in terms of their use of electricity and the flexibility to retailers in managing the elasticity of its aggregated demand (Kirschen, 2003, p. 522).

proactive ones analyzing on the EU level and providing suggestions (He et al., 2013, p. 3). He et al. (2013, p. 3) call consumers 'prosumers' in a sense that consumers consume and, at the same time, produce and provide electricity. Bradley et al. (2013, p. 319) also point out that the result of the CBA would be different depending on the extent to which consumers participate in the market and the DR programs.

On top of that, an appropriate regulatory framework is essential which includes tariff structures and appropriate institutional arrangements (Strbac, 2008; Bradley et al., 2013, p. 322). According to the different regulatory circumstances, the degree of the customers' participation would also vary.

1.5 Conclusion

In this Chapter 1, we have briefly looked at the general idea and background of the introduction of DR. In particular, as we have looked at the background of introducing DR in South Korea, we could realize that in which situation DR is necessary, and that in which context DR will play more important roles. The more detailed background and motivations of the introduction of DR in South Korea and France will be explained in Chapter 2.

On top of the background in reality, the theoretical rationale of DR in Economics provided us with more elaborated explanations on the roles and impacts of DR at the electricity market. We figured out that if we introduce the time-varying tariff scheme, i.e. PBPs, we can increase social welfare. Moreover, as we offer DR on the wholesale market and, at the same time, reduce the electricity loads physically during the peak periods, it can decrease the marginal electricity supply costs, and, in turn, decrease the price of electricity. This also has an impact on the elasticity of demand for electricity as well as on the security of supply.

As a part of the literature review, the definition of DR and the categorizations of DSM and DR made clearer our understanding of DR and the distinctions with other concepts, such as EE, SG. Moreover, this categorization allowed us to clarify the positioning of this research's subject and to narrow down the scope of it.

We found that DR has a variety of advantages in many aspects. It can increase the efficiency of the power system as DR decreases unnecessary capacity installations and related resources. Also, DR enhances the security of supply by reducing the peak loads. Reducing loads during the peak periods means more flexibility for the system operators. In addition, as DR deters additional capacity expansions, we can avoid the additional costs for transmission and distribution. All these effects lead to environmental benefits, such as less GHG emissions, fewer power plants, and less transmission and distribution installations. Lastly, DR is helpful for the easier integration of RESs.

However, we also specified the challenges to overcome in order to make good use of DR. These days the technological issues are less problematic, but the framework and market design, and the rational CBAs for DR programs should be dealt with more. These issues offered the motivations of this research.

§Chapter 2

Case Studies: The U.S., France, and South Korea

2.1 Case of the U.S.

The case study of the U.S. is quite important because the U.S. has been the leading country in terms of DSM and DR programs, and therefore, it can play a role as the reference case for other following countries, such as the European and Asian countries which are promoting DSM and DR programs recently. The DSM and DR programs of the U.S. can be traced to the history in the early 1970s. In the early 1970s, utilities made use of load management programs and interruptible/curtailable tariff schemes. In the late 1970s and 1980s, with the IRP^[1] utilities increasingly realized the system cost impacts for meeting peak loads and began to consider load management as a reliability resource. In the mid-1990s, there was the restructuring of the electricity markets in the U.S., and with the problems in many restructured electricity markets, policymakers concluded that all forms of DR are essential to the efficient functioning of wholesale electricity markets (Cappers et al., 2010, p. 1527).

The concept of DSM in policy can be found for the first time in the USA's 'National Energy Conservation Policy Act' and 'PURPA', which were introduced as part of the 'National Energy Act 1978' (Warren, 2014, p. 944). This was the first case of DSM being legislated nationally as a solution to the energy security issues of the 1970s. DSM programs grew in the U.S. in the 1980s and 1990s, and by 1995, 600 energy utilities had conducted 2,300 programs involving 20 million participants. Notably, between 1989 and 1995, 260,000 gigawatt-hours (GWh) were saved from cumulative spending of USD 14 billion. Since 1995 DSM programs declined in the U.S. as energy security issues became less prominent at that time.

On the contrary, at this moment, the U.S. Federal Government is promoting demand-side resources as the federal government entitled the same value and status to demand-side resources as supply and generation-side resources in capacity markets. In line with the government's active support for it, it is worthwhile noting down that the 'Energy Policy Act (EPACT) 2005' set the key objective of the U.S. national energy policy that 'it should eliminate unnecessary barriers to the wholesale market DR participation in energy, capacity, and ancillary service markets by customers and LAs, at either the retail or wholesale level' (Cappers et al., 2010, p. 1527).

As a result of the government's strong initiatives, it was estimated that the potential size of peak load reductions from then existing DR resources, relative to national peak demand, was about 5% in 2006 and grew to 5.8% in 2008 (Cappers et al., 2010, p. 1527). In 2008, about 93% (about 38,000MW) of the peak load reduction from then existing DR resources in the U.S. was provided by various types of 'incentive-based' programs—compared to the 'time-based' retail rates (2,700MW). Overall, residential and commercial customer DR resources account for 30% (8,600 MW) and 23% (6,462 MW) of the 2012 national potential peak reduction from 'retail programs', respectively—for industrial customer DR resources, it was about 46.5% (13,261 MW) (Fed-

^[1] It was introduced by 'Public Utility Regulatory Policy Act (PURPA)' in 1978, and the IRP involved energy utilities evaluating options for meeting future electricity demands and providing energy services at minimal societal costs to customers (Warren, 2014, p. 944).

eral Energy Regulatory Commission, 2014, p. 10). The potential peak reduction from RTO and ISO DR programs increased by 9.3% (2,452 MW) from 2012 to 2013—as a percentage of total peak demand, it was 5.6% of peak demand in 2012 and 6.1% in 2013 (Federal Energy Regulatory Commission, 2014, p. 10).

The Federal Energy Regulatory Commission (2014, p. 1) concluded in its annual report^[2] that potential peak reduction from DR in the RTOs, ISOs, and Electric Reliability Council of Texas (ERCOT) markets increased by 2,451 MW to 28,503 MW from 2012 to 2013 or 9.3%. Also, the report highlighted that DR resources made significant contributions to balancing supply and demand during the late 2013 and early 2014 extreme cold weather events and helped preserve Eastern RTO and ISO reserve levels.

The extreme cold weather events in the eastern U.S. happened during the period of January 6-8 and January 17-29, 2014 (Federal Energy Regulatory Commission, 2014, pp. 12–13). It caused a sudden high demand for electricity and generation outages. It was a harsh challenge for the eastern RTO/ISOs, and they had to rely on DR to balance the supply and demand and to avoid reserve shortages. Actually, PJM called on 2,000 MW of DR during the morning and evening peaks on Jan. 7, and more than 2,500 MW of DR on Jan. 23 and 28. In fact, for the period there was no obligation for clients to respond to the call, but about 25% of registered demand resources activated, which proved the ‘year-round value of DR’. In order to deal with the same situation, New York Independent System Operator (NYISO) activated the ‘Emergency Demand Response Program’ and a ‘Special Case Resources’ capacity market program on January 7 and called on the demand reductions of about 900 MW.

Nowadays various DR products are provided by a number of DR programs throughout the U.S. (Paterakis et al., 2017; Smart Electric Power Alliance (SEPA), 2018). Some of them are operated by RTOs/ISOs, and others are operated by utilities. However, as this research is focusing on DR programs which provide energy (capacity or ancillary services) in the wholesale market (capacity market or ancillary services market), we will review these kinds of DR programs run by major RTOs/ISOs, such as ISO New England (ISO-NE), NYISO, California Independent System Operator (CAISO), and PJM.

In ISO-NE, the Price Responsive Demand (PRD) was fully integrated into energy and operating reserve markets on June 1, 2018 (Smith, 2017), which means DR resources in the PRD can participate in the day-ahead and real-time market and provide energy, and in the real-time and forward reserve market to provide operating reserves. Moreover, it has the same opportunity to participated in the capacity market. In detail, in the new PRD framework, Demand Response Resources (DRRs), which is also called active demand resources, can participate in the energy and reserve markets. If DRRs participate in the Forward Capacity Market (FCM), it is mapped into and called Active Demand Capacity Resources (ADCRs). For the DRRs, participants [with Demand Response Assets (DRAs)] can bid in the day-ahead and real-time energy market, and if the offers are accepted, it can be dispatched by ISO-NE. It receives wholesale market payments like other generating resources. For the CBL calculation, ISO-NE utilizes the average load over ten most recent weekdays excluding holidays and DR event days (called dispatch days) with the adjustment (Lehman, 2019, p. 22). It is an additive adjustment, and the interval or range for the additive adjustment is the fifteen minutes—it is equivalent to the three-time slots because the unadjusted CBL is calculated for every five minutes—immediately prior to startup instruction of the DR event (Lehman, 2019, p. 29).

NYISO administers four DR programs (New York Independent System Operator (NYISO), 2020). Among them, the Emergency Demand Response Program (EDRP) is a reliability program and the Day-Ahead Demand Response Program (DADRP) is an economic program, and both of them provide energy in the wholesale market. The other two DR programs are the Installed Capacity – Special Case Resource (ICAP/SCR) program and the Demand-Side Ancillary Services Program (DSASP). The ICAP/SCR program is one of the reliability programs of NYISO supporting emergency operations. The DSASP is one of the economic programs of NY-

^[2] The annual report of the FERC deals with six requirements by ‘Energy Policy Act (EPACT) 2005’, such as ‘existing demand response programs and time-based rate programs, the annual resource contribution of demand resources, the potential for demand response as a quantifiable, reliable resource for regional planning purpose, regulatory barriers to improved customer participation in demand response, peak reduction and critical period programs, and so forth’ (Federal Energy Regulatory Commission, 2014, p. 2).

ISO, and it provides program participants with an opportunity to offer their load curtailment capability into the Day-Ahead Market and Real-Time Market to provide Operating Reserves and Regulation Service. However, for the DADRP, there was no offer submitted since December 2010, and it means it is inactive. When it comes to the two reliability programs, the EDRP and ICAP/SCR, the number of end-use locations is a total of 3,540 and its volume is a total of 1,287.9 MW as of July 31, 2019. This amount represents 4.24% of the 2019 Summer Capability Period peak demand of 30,397 MW. The ICAP/SCR program accounts for 99.5% of the total MW enrolled in the two reliability programs. Therefore, it can be said that in NYISO, the main DR program is the ICAP/SCR program. In addition, the data from the previous 30 days is utilized for the CBL estimation, and for the actual load reduction, it is paid at the level of the [Locational-Based Marginal Price \(LBMP\)](#).

In CAISO, there are two types of DR resources ([California Independent System Operator \(CAISO\), 2019](#)). The [Proxy Demand Resource \(PDR\)](#) provides energy, spin, non-spin, Residual Unit Commitment (RUC) bidding in the Day-Ahead energy market, Day-Ahead and Real-Time Non-Spinning Reserve market, Spinning Reserve market, and 5-Minute Real-Time energy market. It is an economic DR program. The [Reliability Demand Response Resource \(RDRR\)](#) provides energy in the Day-Ahead and reliability Real-Time market, and it is used for reliability purposes (a reliability DR program). In order to calculate CBLs, CAISO basically uses '10-in-10 non-event day baseline methodology' with a bi-directional morning adjustment capped at 20%, called the [Load Point Adjustment \(LPA\)](#) (Morning Adjustment) for the day ([California Independent System Operator \(CAISO\), 2014](#)), and CAISO allows participants to choose alternative baseline methodologies with the CAISO's approval.

In PJM^[3], DR is integrated into PJM's wholesale electricity markets, and, as a result, retail customers have the opportunity to participate in PJM's energy, capacity, and other markets through [Curtailment Service Providers \(CSPs\)](#) ([PJM Interconnection \(PJM\), 2017](#)). For economic demand response, participants have a day-ahead option or a real-time option, and for the reductions with the day-ahead option, it is paid based on the day-ahead prices [[Locational Marginal Prices \(LMPs\)](#)], and, with the real-time option, it is paid based on real-time prices. The capacity market in which DR can participate is called the [Reliability Pricing Model \(RPM\)](#) capacity market. It was designed to secure long-term grid reliability and approved by the FERC on December 22, 2006 ([Pfeifenberger et al., 2008](#)).^[4] It is based on three-year forward-looking. For the 2017/2018 delivery year, a total of about 9,770 MW of DR were traded as capacity resources ([PJM Interconnection \(PJM\), 2017, p. 2](#)). As PJM's DR was a role model for South Korea, PJM's CBL estimation methodologies are closed related to those of South Korea. Therefore, the evolutions of the CBL estimation methods will be explained in more detail in Section 3.2.

^[3] PJM is the largest RTO in the U.S. as a part of the Eastern Interconnection. It is serving all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia (13 states), and the District of Columbia. In addition, at this moment, PJM is the largest competitive wholesale electricity market, including 61 million customers and 183 GW of generating capacity—as of 2013 ([Ott, 2014; Wikipedia, 2017](#)). PJM is a quite important case for South Korea because it seems that it was a kind of role model for South Korea's DR program. In more detail on PJM, please, refer to the official web site of PJM: [On-line], Available: <http://www.pjm.com/>

^[4] Before the PJM's RPM, it was the PJM's [Capacity Credit Market \(CCM\)](#) since April 1, 1999, and it was replaced with the current capacity market design, which is the RPM, on June 1, 2007 ([Pfeifenberger et al., 2008, pp. 6–7; Bowring, 2013](#)). Also, the previous capacity mechanism, the CCM, did not permit the participation of demand-side resources ([Pfeifenberger et al., 2008, p. 6](#)).

2.2 Case of France: NEBEF (La Notification d'Échange de Blocs d'Effacement) Mechanism

2.2.1 Background and Motivations to Introduce NEBEF in France

When it comes to the case of Europe, contrary to the case of the U.S., the emphasis was placed more on Energy Conservation and EE after the energy crisis in the 1970s, and then, due to the market liberalization and deregulation in the 1990s in Europe, many utilities lost their interest on DSM and DR (Warren, 2014, p. 944).^[5]

However, in the 2000s and 2010s, as the issues of climate change and energy security have placed on the political agenda around the globe, DSM could draw attention again. (Warren, 2014, p. 944).

Currently, the European Commission (EC) has expressed its strong support for DR, and the 'Energy Efficiency Directive (2012/27/EU), Article 15.8' outlined clear and specific requirements for the Member States of the EU to encourage DR program development. It is estimated that the peak clipping capabilities with DR in Europe range between 6% and 11% depending on each country's circumstance (Smart Energy Demand Coalition, 2011, p. 5).

It is interesting to have a look at the maps in the report of SEDC (Smart Energy Demand Coalition, 2014, p. 3; Smart Energy Demand Coalition, 2017, p. 11) which shows the situation and the change regarding the activity level of DR in Europe (Fig. 2.1, 2.2, and 2.3). The U.K., Belgium, and Switzerland have been commercially active since 2013. For Ireland, Finland, and France, there was a change from 'Partial opening' to 'Commercially active'. While Poland still remains at the status of 'Preliminary development', there was a change in status for Germany from 'Preliminary development' to 'Partial opening'. Spain and Italy look inactive—'Closed'.

^[5] According to Koliou et al. (2013), regulatory barriers from the member states of the EU were the reason why DR in Europe was lagged behind.

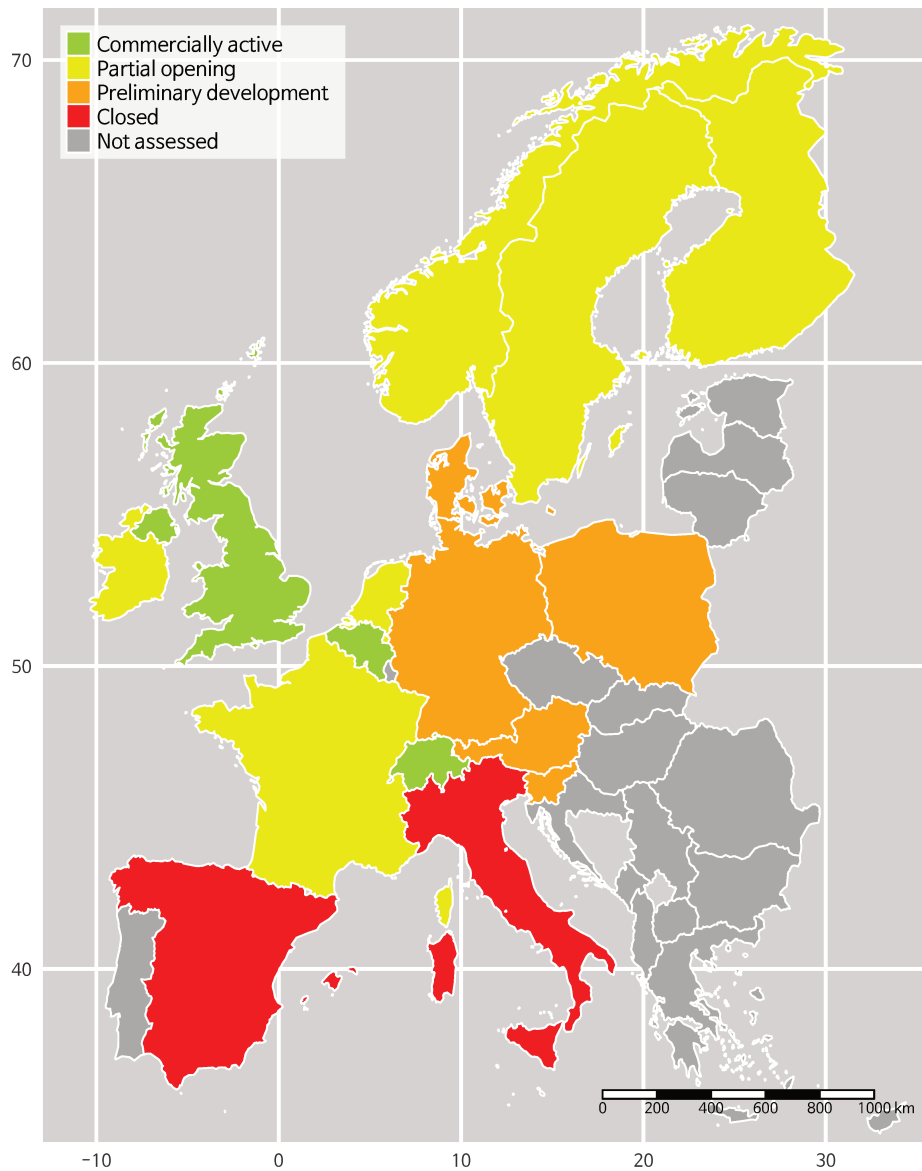


Figure 2.1: DR Map of Europe as of 2013

Source: Recreated by the author, Seungman LEE, based on *Mapping DR in Europe Today: Tracking Compliance with Article 15.8 of the Energy Efficiency Directive*, by Smart Energy Demand Coalition, 2014, p. 3.

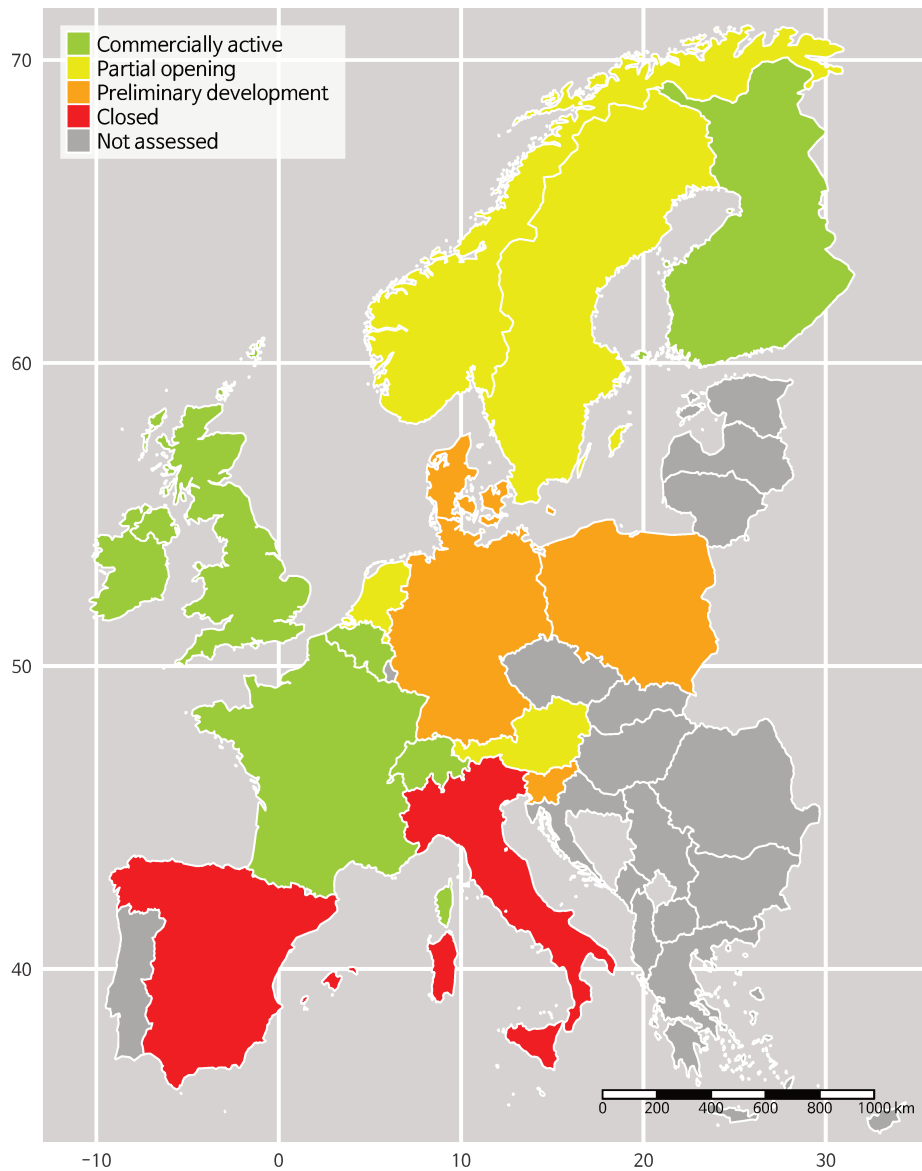


Figure 2.2: DR Map of Europe as of 2014

Source: Recreated by the author, Seungman LEE, based on *Mapping DR in Europe Today: Tracking Compliance with Article 15.8 of the Energy Efficiency Directive*, by Smart Energy Demand Coalition, 2014, p. 3.

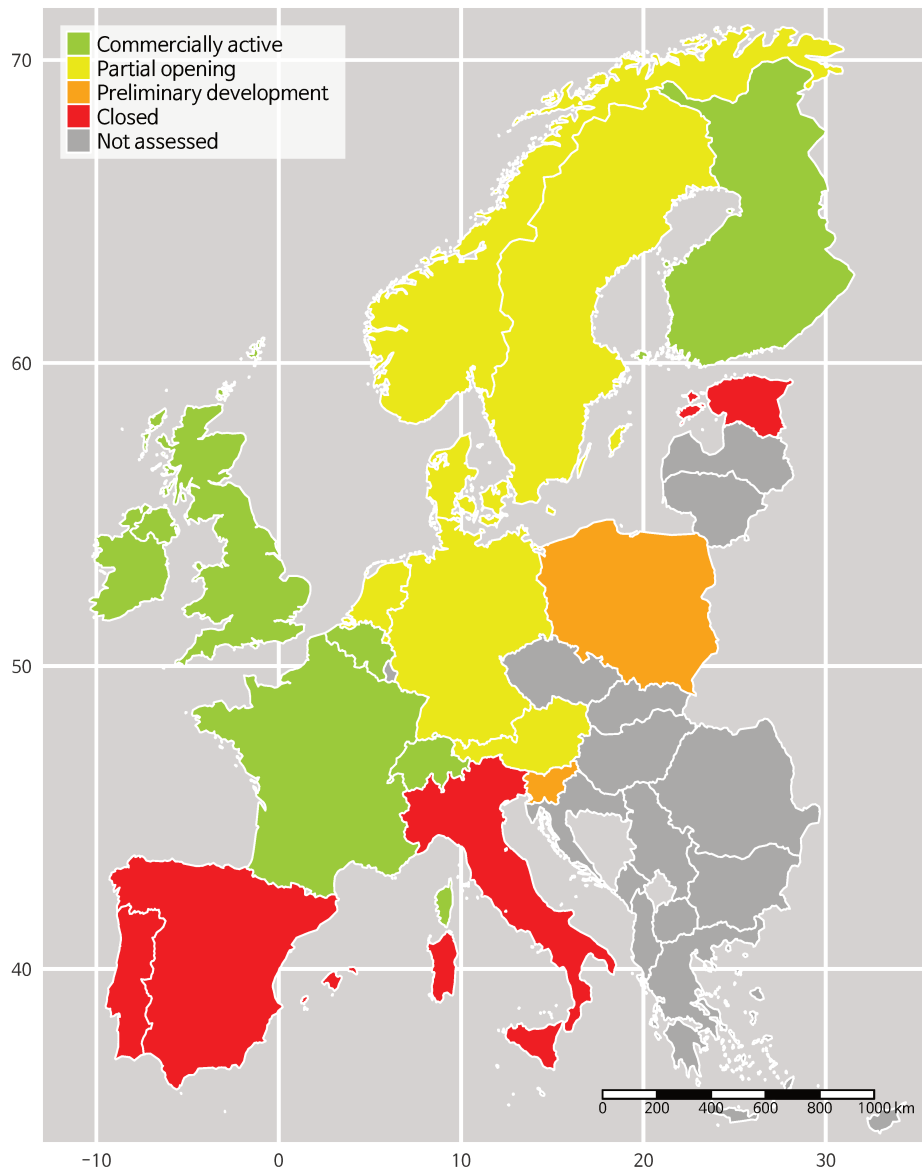


Figure 2.3: DR Map of Europe as of 2017

Source: Recreated by the author, Seungman LEE, based on *Explicit Demand Response in Europe: Mapping the Markets 2017*, by Smart Energy Demand Coalition, 2017, p. 11.

On February 8, 2012, French people have seen the historic peak demand of 102.1 GW (Agora Energiewende, 2015, p. 17). As we can see the following Figure 2.4, the peak load of France increased a lot from 2011 to 2012 because of the increase in the massive use of electric heating in winter and the number of electric appliances in French households whereas, in general, the total installed capacity has been maintained the same (Fig. 2.5 from 2015 to 2017). It means more temperature sensitivity to France (RTE, 2014a, p. 26; RTE, 2014b, p. 33).

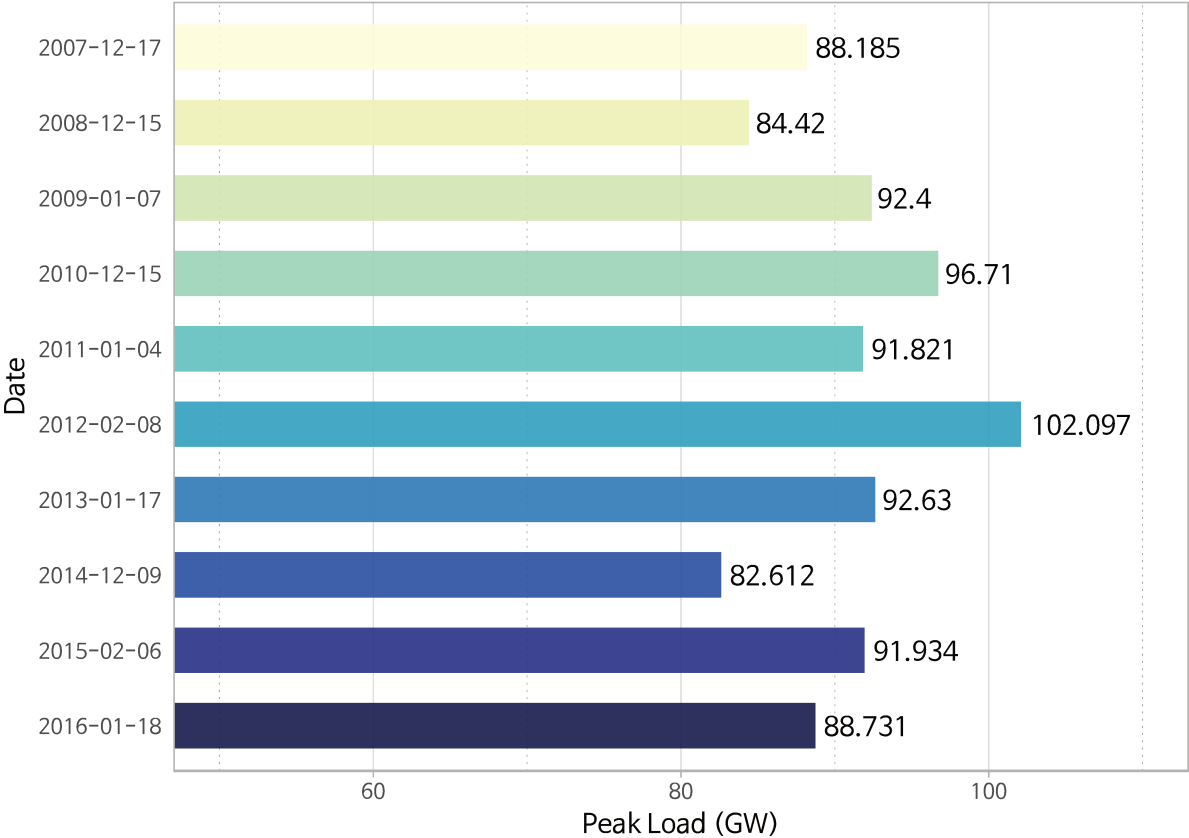


Figure 2.4: France’s Peak Demand over the Past Decade (Since 2007, GW)

Source: *Generation Adequacy Report: on the electricity supply-demand balance in France*, by RTE, 2014b, p. 33; RTE’s PORTAIL CLIENTS, “Historique des consommations journalières en puissance”, [On-line], Available: https://clients.rte-france.com/lang/fr/clients_traders_fournisseurs/vie/vie_stats_conso_inst.jsp

Comparison to South Korea: Fig. 2.16

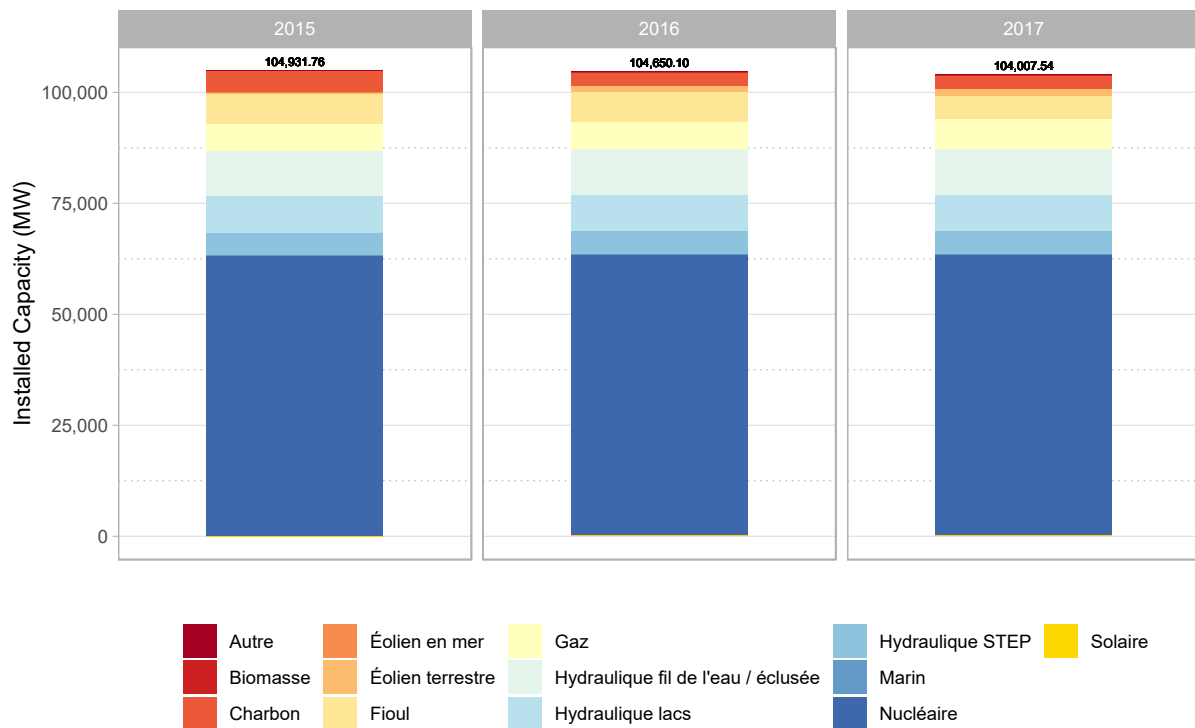


Figure 2.5: The Total Installed Capacity in 2015, 2016, and 2017 (MW)

Source: RTE's PORTAIL CLIENTS, "Capacité installée des unités de plus de 1 MW agrégée par filière de production", [On-line], Available: https://clients.rte-france.com/lang/fr/clients_traders_fournisseurs/vie/prod/parc_reference.jsp

Compared to the Heatmaps of South Korea's Loads in 2015 (Fig. A.20) and 2016 (Fig. 2.15) in the following section, in general in France, the peak load happens in winter during a year, and 8 to 13 and 18 to 20 during a day (Fig. 2.6)^[6] [With the previous Fig. 2.4, for the last decade from 2007 to 2016, all the peak loads of France happened at 7 p.m. (19:00) in winter]. During the winter peak, the high usage of electricity comes from using electric appliances for heating and cooking in the evening. However, during the summer, it shows the low usage of electricity because the rate of the installation and utilization of the air-conditioning appliances for cooling is low in France (the low penetration of air-conditioning) compared to South Korea.

^[6] The heatmaps of loads in France, 2014 (Fig. A.5) and 2015 (Fig. A.6) are in [Appendix A: Supplementary Figures & Tables](#).

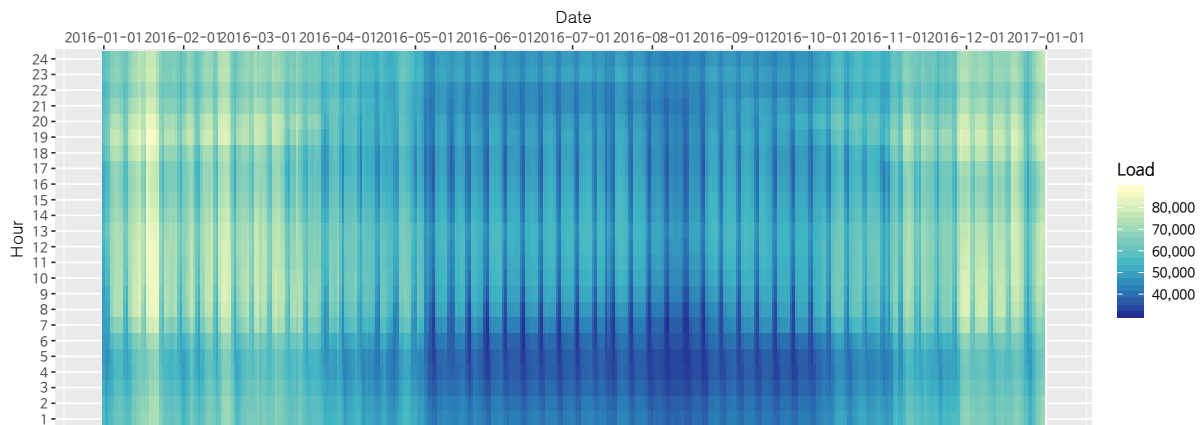


Figure 2.6: Heatmap of Loads, France in 2016 (MW)

Source: 'Data provided by ENTSO-E'. ENTSO-E, "Consumption Data", [On-line], Available: <https://www.entsoe.eu/data/data-portal/consumption/Pages/default.aspx>

Comparison to South Korea: Fig. 2.15

France imports the expensive electricity from its neighbors to meet the peak-load for electric heating during the extremely cold winters. With the different circumstances and energy mix, the motivations for DR in France seems a little bit different from the case of the UK or Germany: the motivations of France have more weights on affordability and sustainability,^[7] but the motivations for DR in Germany put emphasis on the need of back-up for the high penetration or integration of RESs (Koliou et al., 2013, p. 4).

France is the only Member State in Europe which has opened all the wholesale market, capacity market, and ancillary service markets to DR and independent aggregators (Bertoldi et al., 2016, p. 44). France is also one of the only three Member States (Finland, UK, and France) where residential consumers are also engaged.

Looking at the history of DR in France, since 2003, large industrial customers participated in the balancing mechanism, and from 2007, the first pilots were run in order to introduce aggregate residential loads to the mechanism (Bertoldi et al., 2016, pp. 44–45). In 2014, an industrial consumer, for the first time, provided its energy reduction as a **Frequency Containment Reserves (FCR)** or **Primary Reserve (PR)**.

France has a history of successful DR programs led by **Électricité de France (EDF)**, the biggest electricity producer and supplier in France, providing the programs for residential customers (pricing programs) and industrial clients (load balancing programs). There is one famous example of DR in France. That is the EDF's **Tempo tariff**,^[8] which targeted on residential customers with peak and off-peak rates, one of ToU mechanisms (Clastres, 2011, p. 5402). As of 2009, the number of households that opted for the Tempo tariff was 350,000 in France (Koliou et al., 2013, p. 4). It is a valuable case because market-based mechanisms, such as DR tariffs, have been mainly concentrated only on the largest industrial consumers so far (Warren, 2014, p. 947).

Recently, France's regulator, the **Réseau de transport d'électricité (RTE)**, the French transmission system operator, designed and established the capacity market in which it is open for aggregated demand-side resources. The first delivery year was 2016/2017.^[9] For this target, the government studied the adequate amount

^[7] It was estimated that with a price-based DR program, dynamic pricing, it could result in a six percent cut of the peak load on the French electricity production system (Faruqui et al., 2010).

^[8] In detail, the EDF's Tempo tariff was initiated in 1996 (on a full-scale basis after a pilot program). It consists of two pricing periods, peak and off-peak, and of three day types, Blue Days, White Days, and Red Days. The peak hours are from 6 a.m. to 10 p.m., and off-peak hours are from 10 p.m. to 6 a.m. The Blue Days are the least expensive 300 days, the White Days are the normally priced 43 days, and the Red Days are the most costly 22 days for the peak period a year (Faruqui and Sergici, 2010, pp. 204–205). Contrary to the categorization of the Tempo tariff by Clastres (2011), the IEA, OECD (2003, p. 33) categorized the Tempo tariff as one of critical peak pricing (CPP) programs.

^[9] In January 2015, a decree was signed to implement the national peak power capacity mechanism starting in the winter of 2016/2017 (Deloitte, 2015, p. 13).

of capacity 5 years before the delivery year. After that, they finished the procedure of capacity certification and rebalancing for existing generation capacities and for new capacities and DR capacities during the DY-4 (4 years before the delivery year) and DY-2 (2 years before the delivery year), respectively.

One of the critical issues related to DR in France is the ‘sourcing costs’ (Bertoldi et al., 2016, p. vi and pp. 47–48). Sourcing costs are costs incurred by the [Balancing Responsible Parties \(BRPs\)](#)/retailer when they purchase electricity in advance in order to ensure sufficient amounts to meet the electricity consumption of their clients. If consumers decrease their consumption as they participate in a DR program, the BRP loses some part of their expected revenues because they cannot recover the sourcing costs spent. Because this loss is not derived from any competitive activity at the market, BRP/retailers argue that LAs should pay them for these losses. However, in response to their argument, there are two different points of view in France: one from the perspective of 1) the French LAs working with industrial/commercial consumers, and another from the perspective of 2) the French LAs working with residential consumers. French LAs working with industrial/commercial consumers agree that LAs should pay these losses for BRPs, that it is a fair solution in principle. In contrast, the LAs working with residential consumers argue that these payments would destroy their business model and that it will hinder the consumers from participating in the DR programs because the DR participants and LAs have to pay back the majority of their benefits to the retailers—about 85% of their margin (Bertoldi et al., 2016, p. 133). This issue is closely related to the remuneration scheme for DR participants and to the [Net Benefit Test \(NBT\)](#), [Net Benefit Test Price or Net Benefit Threshold Price \(NBTP\)](#) in the DRTM of South Korea and transfer (Versement) in French NEBEF in that the NBTP is the price that makes the loss of producer (or supplier) surplus and the increased consumer surplus equal from the entire societal perspective, and that the transfer to the supplier (Versement) is for filling up these sourcing costs. In line with the conclusion of the report (Bertoldi et al., 2016), we are going to confirm the policy implication that we need to pay attention to the design of the DR market in terms of the DR remuneration scheme and the sourcing cost payment mechanism as we analyze the different results of the CBAs in South Korea and France.

2.2.2 Introduction of NEBEF

The French Law No. 2013-312, known as the ‘Loi Brotte’ (Brottes Law) (Legifrance, 2013), it was signed by the French President on April 15, 2013. This law introduced into the ‘French Energy Code’ new articles concerning the selling of demand reduction in energy markets and in the balancing mechanism. It aims for the prior implementation of the use of demand reduction in the form of an experimental process to be conducted by RTE after authorization by the French Regulatory Commission for Energy [[La Commission de Régulation de l’Énergie \(CRE\)](#)].

The test phase of the French DRM, called [La Notification d’Échange de Blocs d’Effacement \(NEBEF\)](#),^[10] took place from December 2013 to December 2014 on the wholesale market. The decree, ‘Décret n° 2014-764 du 3 juillet 2014’ (Legifrance, 2014), complemented the regulatory framework. Also, with ‘Délibération de la CRE du 17 décembre 2014’ (Commission de Régulation de l’Énergie (CRE), 2014), CRE has extended the experimental process and turned it into a new set of rules.

Since then, ‘Règles NEBEF 1’, the initial regulation on the NEBEF mechanism, has been evolving, and the latest regulation on the NEBEF mechanism is ‘NEBEF 3.1’ (RTE, 2018a)^[11] which is in effect since Jan. 1, 2018. Thanks to this law, decree, and other regulations, since 2013 it is possible to value load curtailment in

^[10] Originally it was called ‘Electricity Load Reductions’ in English, but recently it is translated literally as ‘The Block Exchange Notification of Demand Response (NEBEF) mechanism’.

^[11] ‘Règles NEBEF 3.1’ is the latest rules regarding the selling of demand reduction on the energy markets. Its full title is les ‘Règles pour la valorisation des effacements de consommation sur les marchés de l’énergie NEBEF 3.1’. In addition to Règles NEBEF 3.1, there is another rule, so-called ‘Règles SI NEBEF 3.1’ (RTE, 2018b). It is the NEBEF IT rule which concerns access to the information systems such as the RTE information system and the information system of the DSO.

the energy market (Day-ahead market and Intraday market) and balancing market (Rious *et al.*, 2015, p. 132), that is, the resources of DR can participate in those two markets. Now it leads to the full participation of DR in all the existing market structures in France (Latour, 2015). France is the only country in Europe to allow DR operators to participate directly in the wholesale markets as a resource (direct participation) (Veyrenc, 2014, p. 13).

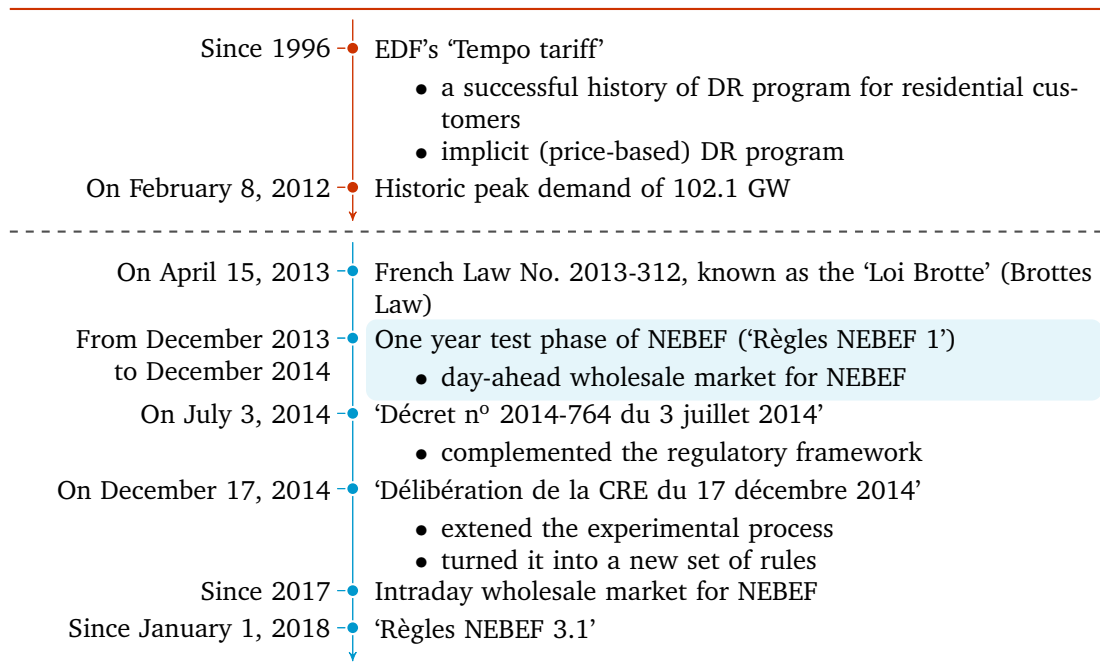


Figure 2.7: Timeline around Background and Introduction of French NEBEF

2.2.3 Evolution of NEBEF

As seen in Table 2.1,^[12] at the beginning of NEBEF in 2014, the total volume of NEBEF was quite small (about 620 MWh) even though there were the reserved and realized volumes of NEBEF throughout the year of 2014 except February. In January and September, there were quite significant amounts of the NEBEF in total compared to other months. Moreover, in terms of the difference between the volume of reserved and realized NEBEF, even though we can observe that sometimes reserved NEBEFs were not fulfilled, the difference was quite small, about 10% of the reserved NEBEF in 2014.

^[12] You can find the visualization (Fig. A.7 and A.8) of the table in [Appendix A: Supplementary Figures & Tables](#). Also, Figure A.9 and A.10 are given as a reference for comparing the two volumes of NEBEF, 'Programmes d'Effacement Retenus agrégés' and 'Chroniques d'Effacement Réalisé agrégées' side-by-side in 2014.

Table 2.1: The Monthly Reserved and Realized NEBEF Volume and Total in 2014 (MW)

Month	Reserved or Planned NEBEF (Programmes d'Effacement Retenus agrégés)	Realized NEBEF (Chroniques d'Effacement Réalisé agrégées)
1	134.400	119.286
2	0.000	0.000
3	4.000	3.849
4	17.400	15.742
5	5.200	5.780
6	35.600	40.270
7	34.600	32.439
8	53.000	47.450
9	236.000	203.260
10	82.400	68.382
11	40.600	38.689
12	50.400	45.319
Total in 2014	693.600	620.467

Source: RTE's PORTAIL CLIENTS, "Volumes d'Effacement NEBEF, tous Opérateurs d'Effacement confondus, agrégés à la maille France", [On-line], Available: https://clients.rte-france.com/lang/fr/visiteurs/vie/nebef_effacements.jsp

Looking at the following NEBEF indicated **Load Duration Curve (LDC)**^[13] (Fig. 2.8)^[14] we can see that there were heavy loads in winter and light loads in summer in 2014.^[15] Also, we can see that at the beginning of the year, that is January, February, and March, even though there were heavy loads in winter, NEBEF was not activated, and since September, even though there were not heavy loads, NEBEF was activated often. With this observation one may think that NEBEF could be actualized even if it is not for the peak load, that is, NEBEF can be utilized even in summer where there are relatively higher reserve rates than that in winter. However, I think it is because of the fact that at the beginning of the NEBEF program, it was not very well known among potential participants and not very well organized yet.

^[13] ⦿ A LDC is a profile of system demand for specified periods of time, for example, annual. It is graphed as a histogram, a cumulative distribution function (CDF) (Cardell, 2018). The loads can be categorized into three: 1) base load, 2) intermediate load, and 3) peak load. The ranges for three loads are not absolute, but relative.

^[14] ⦿ The original LDC (Fig. A.11) and detailed information are given in Appendix A: Supplementary Figures & Tables. Figure 2.8 is the same load duration curve with Figure A.11 except that I indicated in red the load of the specific hour in which there was the actualized NEBEF. Therefore the y-axis is still the hourly load value (MW) not the amount of the actualized NEBEF.

^[15] ⦿ Also, in general, higher variability of loads compared to South Korea—relatively large standard deviation (**Std.Dev**) in Tab. A.3 and longer interquartile range (**IQR**) in Fig. A.12 in Appendix A: Supplementary Figures & Tables.

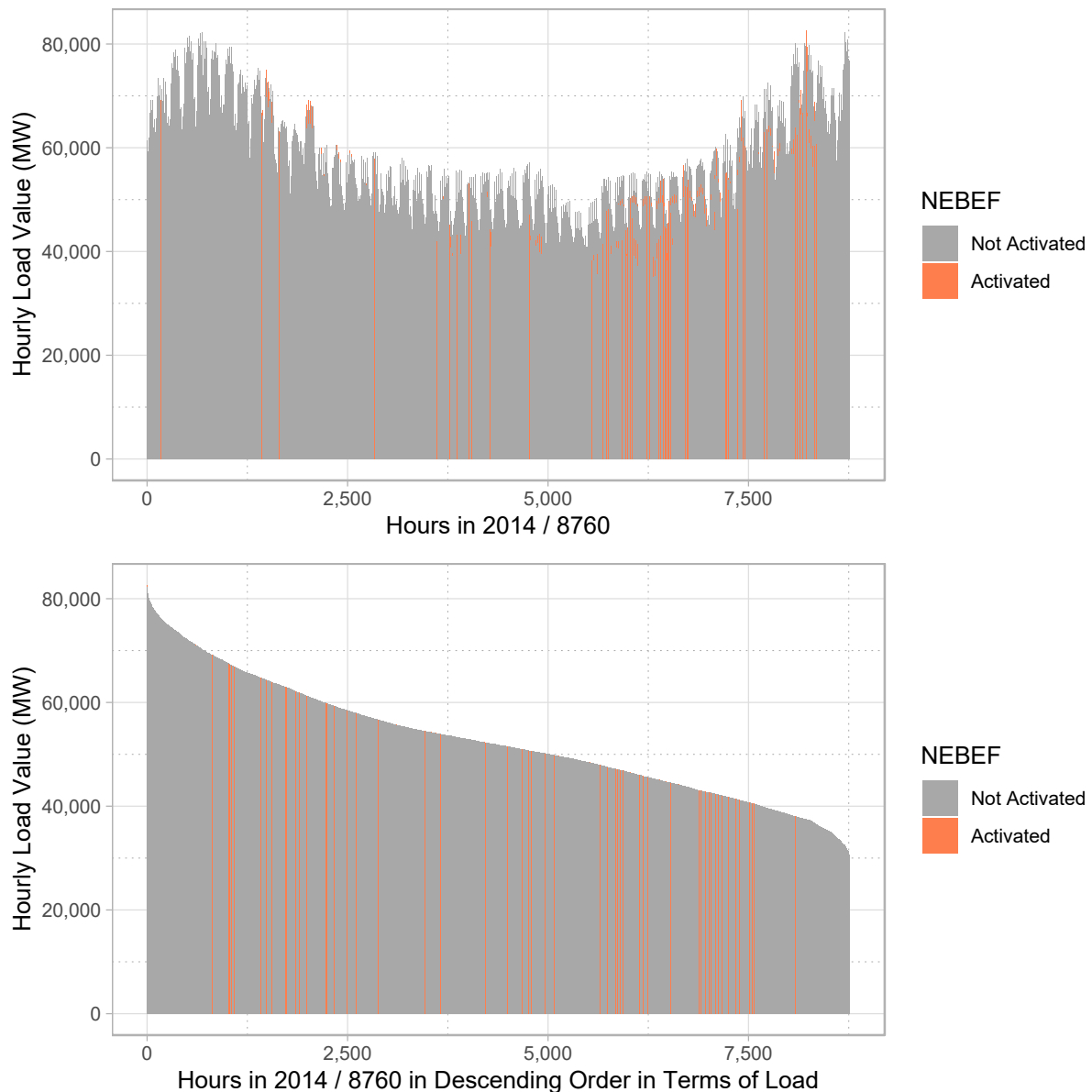


Figure 2.8: Load Duration Curve of France in 2014 (MW) Considering NEBEF Actualized Days

Source: 'Data provided by ENTSO-E', ENTSO-E, "Consumption Data", [On-line], Available: <https://www.entsoe.eu/data/data-portal/consumption/Pages/default.aspx> ; RTE's PORTAIL CLIENTS, "Volumes d'Effacement NEBEF, tous Opérateurs d'Effacement confondus, agrégés à la maille France", [On-line], Available: https://clients.rte-france.com/lang/fr/visiteurs/vie/nebef_effacements.jsp

As seen in Table 2.2,^[16] the total volume of NEBEF increased to about 2,970 MWh in 2015—it is about five times from the year of 2014. However, there were the reserved and realized volumes of NEBEF only in January, February, August, September, November, and December in 2015. In January and February, its amount was negligible, and in August and September, the amount was quite small. In contrast, in November and December, there were quite significant amounts of the NEBEF in total for each month.

^[16] You can find the visualization (Fig. A.13, and A.14) of the table in Appendix A: Supplementary Figures & Tables. Also, Figure A.15 is given as a reference for comparing the two volumes of NEBEF, 'Programmes d'Effacement Retenus agrégés' and 'Chroniques d'Effacement Réalisé agrégés' side-by-side in 2015.

Table 2.2: The Monthly Reserved and Realized NEBEF Volume and Total in 2015 (MW)

Month	Reserved or Planned NEBEF (Programmes d'Effacement Retenus agrégés)	Realized NEBEF (Chroniques d'Effacement Réalisé agrégées)
1	0.600	0.660
2	0.200	0.291
3	0.000	0.000
4	0.000	0.000
5	0.000	0.000
6	0.000	0.000
7	0.000	0.000
8	18.100	4.372
9	16.800	5.243
10	0.000	0.000
11	1,713.388	1,632.000
12	1,425.000	1,328.000
Total in 2015	3,174.089	2,970.304

Source: RTE's PORTAIL CLIENTS, "Volumes d'Effacement NEBEF, tous Opérateurs d'Effacement confondus, agrégés à la maille France", [On-line], Available: https://clients.rte-france.com/lang/fr/visiteurs/vie/nebef_effacements.jsp

As can be seen in Figure 2.9,^[17] in 2015, NEBEF is less frequently activated than in 2014 even though there were larger total consumption and higher peak load in 2015 than in 2014.

^[17] The original LDC (Fig. A.16) and detailed information are given in [Appendix A: Supplementary Figures & Tables](#).

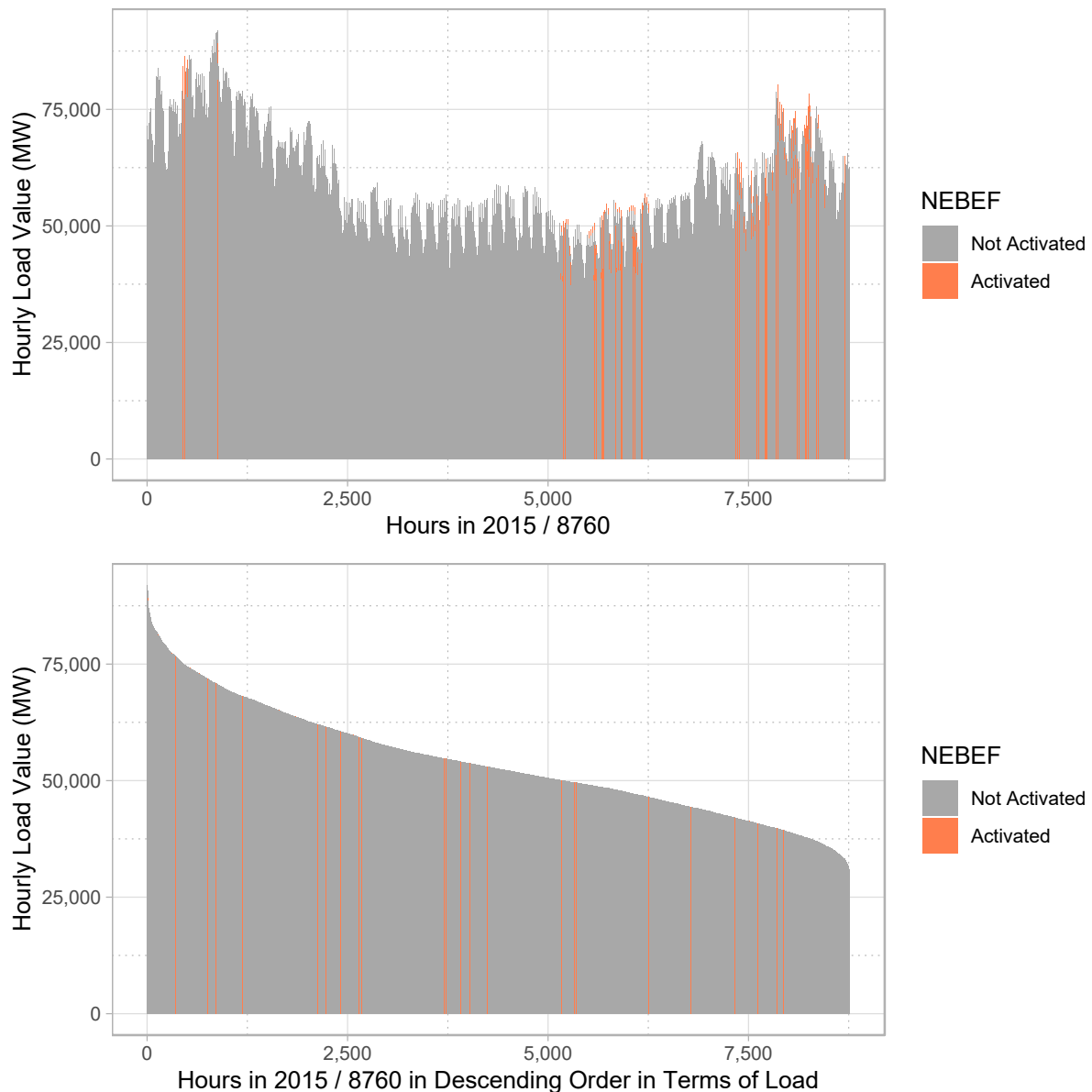


Figure 2.9: Load Duration Curve of France in 2015 (MW) Considering NEBEF Actualized Days

Source: 'Data provided by ENTSO-E', ENTSO-E, "Consumption Data", [On-line], Available: <https://www.entsoe.eu/data/data-portal/consumption/Pages/default.aspx> ; RTE's PORTAIL CLIENTS, "Volumes d'Effacement NEBEF, tous Opérateurs d'Effacement confondus, agrégés à la maille France", [On-line], Available: https://clients.rte-france.com/lang/fr/visiteurs/vie/nebef_effacements.jsp

As can be seen in Table 2.3, Figure 2.10,^[18] and Figure 2.11, as time goes by, NEBEF has been significantly developed in terms of the total volume (about 20,622 MWh) and the frequency of activation in 2016. There were the reserved and realized volumes of NEBEF throughout the entire year of 2016. Almost all the months show quite significant amounts of the NEBEF in total for each month, especially October, November, and December compared to the previous years. Those intensive NEBEF offers at the end of 2016 were due to

^[18] In Appendix A: Supplementary Figures & Tables, Figure A.17 and Figure A.18 are given just for a reference comparing the two volumes of NEBEF, 'Programmes d'Effacement Retenus agrégés' and 'Chroniques d'Effacement Réalisé agrégés' in 2016.

high wholesale prices mainly because of the nuclear power plants' unavailability and cold temperature (Smart Energy Demand Coalition, 2017, p. 85). Considering the performances of all the previous years 2014, 2015, and 2016, we can see the developing trend of NEBEF.

Table 2.3: The Monthly Reserved and Realized NEBEF Volume and Total in 2016 (MW)

Month	Reserved or Planned NEBEF (Programmes d'Effacement Retenus agrégés)	Realized NEBEF (Chroniques d'Effacement Réalisé agrégées)
1	1,883.000	1,827.205
2	505.392	499.902
3	519.796	500.793
4	199.000	194.889
5	49.000	51.778
6	76.400	74.190
7	293.600	287.120
8	250.000	243.550
9	264.200	251.351
10	3,481.600	3,059.250
11	5,953.800	5,367.721
12	8,694.600	8,263.972
Total in 2016	22,170.388	20,621.721

Source: RTE's PORTAIL CLIENTS, "Volumes d'Effacement NEBEF, tous Opérateurs d'Effacement confondus, agrégés à la maille France", [On-line], Available: https://clients.rte-france.com/lang/fr/visiteurs/vie/nebef_effacements.jsp

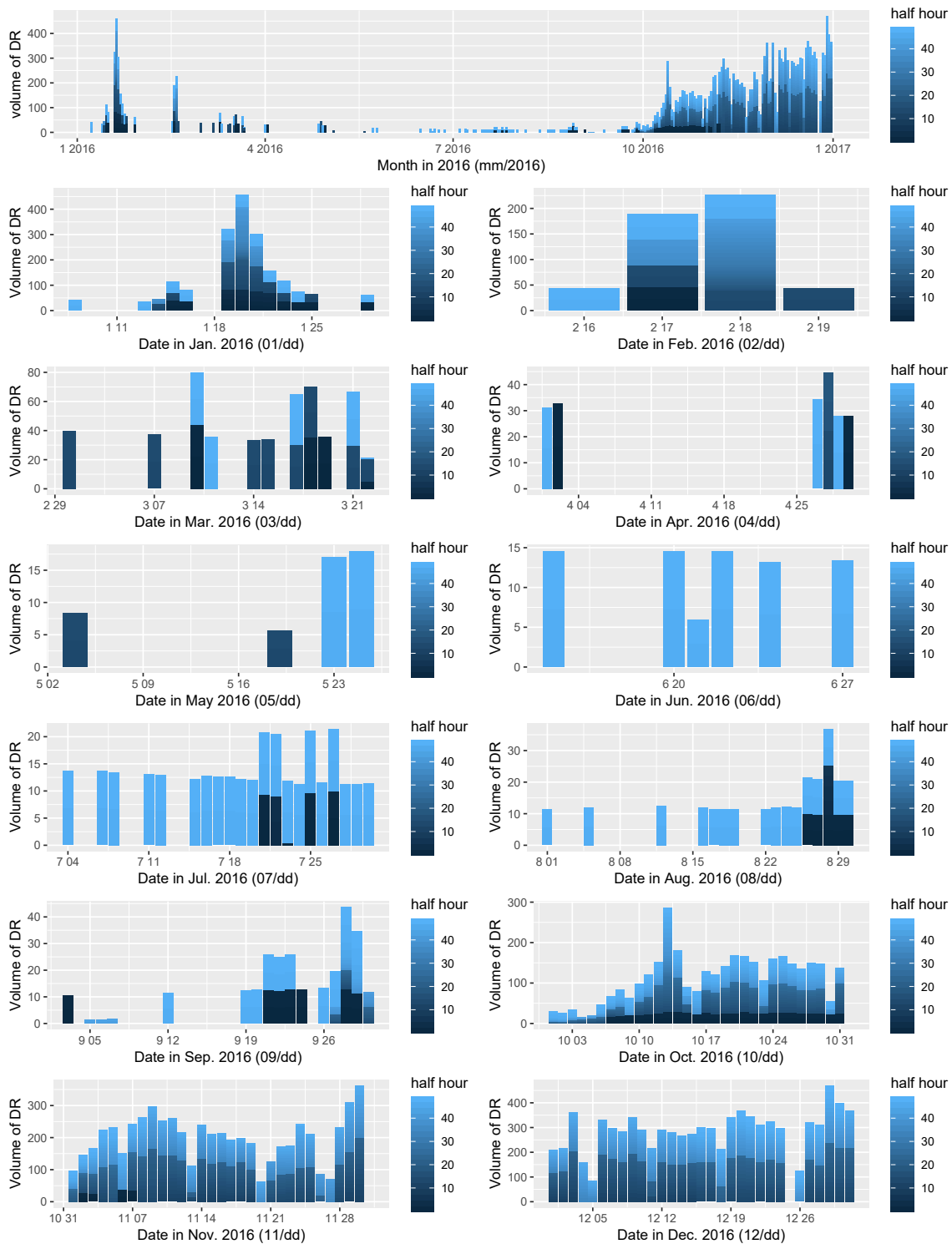


Figure 2.10: The Volume of Demand Reduction of France in 2016 (Programmes d’Effacement Retenus agrégés, MW)

***half hour:** it means that the interval of the NEBEF is 30 minutes. For example, if the number of ‘half hour’ is 20, it means the volume between 09h30 and 10h00, and if it is 38, it means the volume between 18h30 and 19h00, etc.

Source: RTE’s PORTAIL CLIENTS, “Volumes d’Effacement NEBEF, tous Opérateurs d’Effacement confondus, agrégés à la maille France”, [On-line], Available: https://clients.rte-france.com/lang/fr/visiteurs/vie/nebef_effacements.jsp

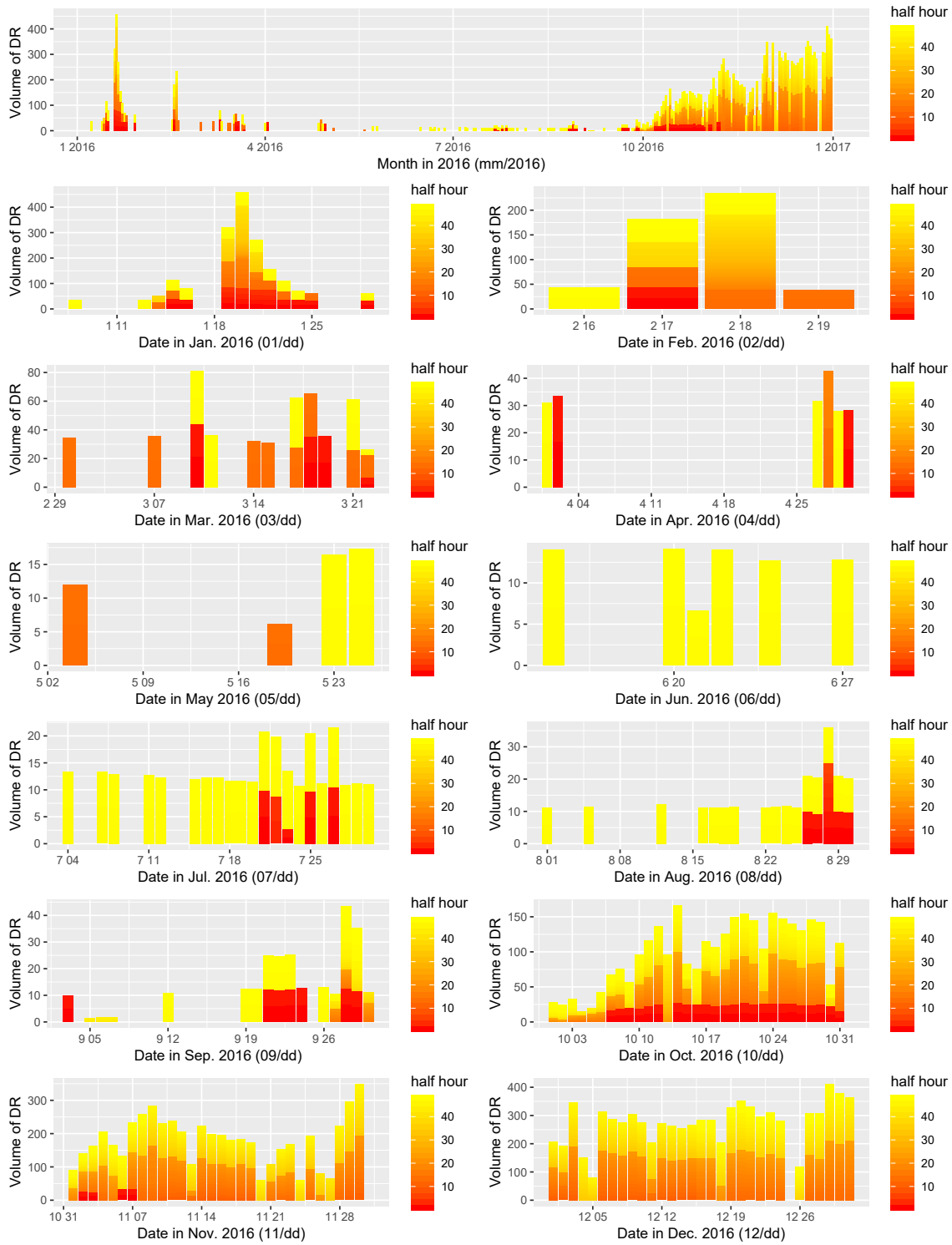


Figure 2.11: The Volume of Demand Reduction of France in 2016 (Chroniques d’Effacement Réalisé agrégées, MW)

***half hour:** it means that the interval of the NEBEF is 30 minutes. For example, if the number of ‘half hour’ is 20, it means the volume between 09h30 and 10h00, and if it is 38, it means the volume between 18h30 and 19h00, etc.

Source: RTE’s PORTAIL CLIENTS, “Volumes d’Effacement NEBEF, tous Opérateurs d’Effacement confondus, agrégés à la maille France”, [On-line], Available: https://clients.rte-france.com/lang/fr/visiteurs/vie/nebef_effacements.jsp

Looking at the NEBEF indicated LDC (Fig. 2.12)^[19] we can see that in 2016 NEBEF was much more frequently activated during the peak hours than the past years. It means it works better considering the objective of the NEBEF mechanism.

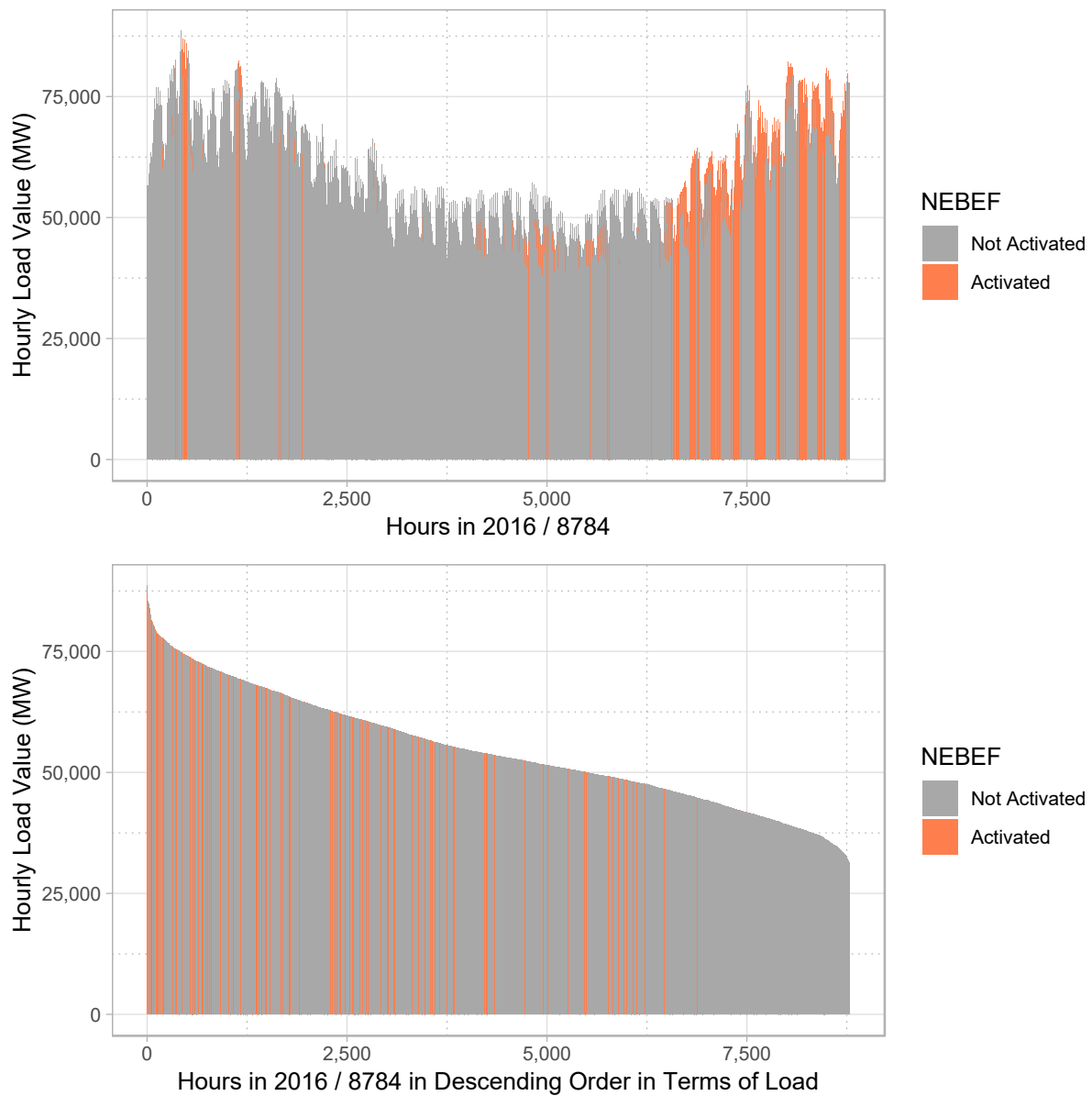


Figure 2.12: Load Duration Curve of France in 2016 (MW) Considering NEBEF Actualized Days

Source: RTE's PORTAIL CLIENTS, "Historique des consommations journalières en puissance". [On-line], Available: https://clients.rte-france.com/lang/fr/clients_traders_fournisseurs/vie/vie_stats_conso_inst.jsp

According to Figure 2.13, we can see that the frequency of the activation of NEBEF is getting higher. Also, we can see the change in the pattern. In 2014 and 2015, NEBEF was mainly actualized during fall and winter. However, in 2016, there are many hours in which NEBEF was actualized not only in fall and winter but also in spring and summer even though the large amount of the actualized NEBEF is positioned after September. In addition, the shape of the actualized NEBEF is getting similar to the shape of the French LDC.

^[19] The original LDC (Fig. 2.12) and detailed information are given in [Appendix A: Supplementary Figures & Tables](#).

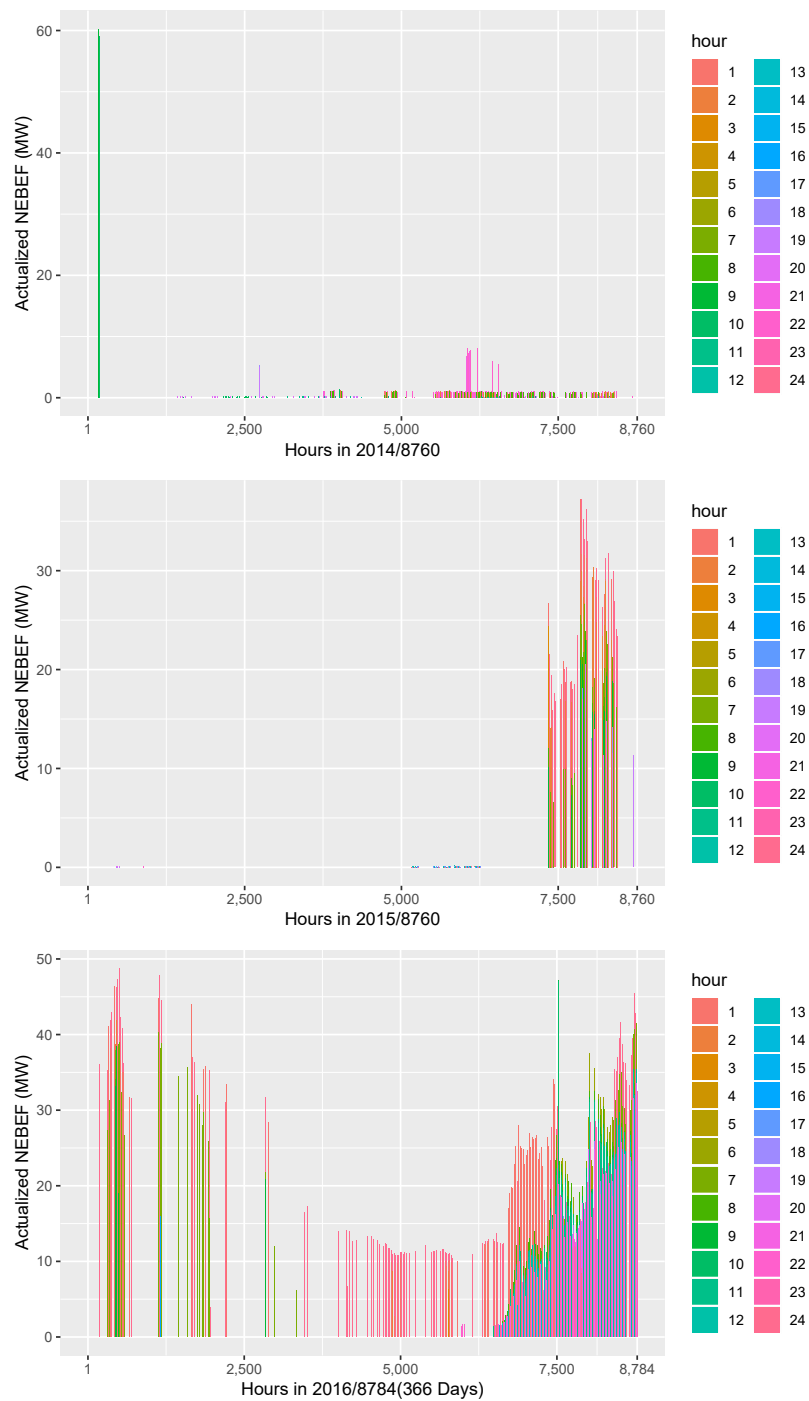


Figure 2.13: Comparing the Chronological Actualized NEBEF between 2014, 2015, and 2016

Source: RTE's PORTAIL CLIENTS, "Volumes d'Effacement NEBEF, tous Opérateurs d'Effacement confondus, agrégés à la maille France", [On-line], Available: https://clients.rte-france.com/lang/fr/visiteurs/vie/nebef_effacements.jsp

Figure 2.14, which is based on a simple heatmap, shows the NEBEF operators (LAs) on the list for each month since November 2016. The total number of NEBEF operators in November 2016 was 18, and then it increased to 23 in May 2017.

	Nov_2016	Dec_2016	Jan_2017	Feb_2017	Mar_2017	Apr_2017	May_2017
ACTILITY -	Yes	Yes	Yes	Yes	Yes	Yes	Yes
ALPIQ ENERGIE FRANCE -	No	No	Yes	Yes	Yes	Yes	Yes
BHC ENERGY -	Yes	Yes	Yes	Yes	Yes	Yes	Yes
BLUE ELEC -	Yes	Yes	Yes	Yes	Yes	Yes	Yes
DANSKE COMMODITIES A/S -	Yes	Yes	Yes	Yes	Yes	Yes	Yes
DIRECT ENERGIE -	Yes	Yes	Yes	Yes	Yes	Yes	Yes
E.ON FRANCE ENERGY SOLUTIONS S.A.S. -	No	No	No	Yes	Yes	Yes	No
ECOMETERING -	Yes	Yes	Yes	Yes	Yes	Yes	Yes
EDF -	Yes	Yes	Yes	Yes	Yes	Yes	Yes
ENERDIGIT -	Yes	Yes	Yes	Yes	Yes	Yes	Yes
ENERGY POOL DEVELOPPEMENT -	No	No	Yes	Yes	Yes	Yes	Yes
ENGIE SA -	No	No	Yes	Yes	Yes	Yes	Yes
EQINOV DEMAND SIDE MANAGEMENT -	Yes	Yes	Yes	Yes	Yes	Yes	Yes
HYDRONEXT -	Yes	Yes	Yes	Yes	Yes	Yes	Yes
ILEK -	Yes	Yes	Yes	Yes	Yes	Yes	Yes
METRON -	Yes	Yes	Yes	Yes	Yes	Yes	Yes
RES REACTIVE FLEXIBILITE SERVICES -	Yes	Yes	Yes	Yes	Yes	Yes	Yes
SMART GRID ENERGY -	Yes	Yes	Yes	Yes	Yes	Yes	Yes
SOLVAY ENERGY SERVICES -	Yes	Yes	Yes	Yes	Yes	Yes	Yes
SOVEN -	Yes	Yes	Yes	Yes	Yes	Yes	Yes
VALORIS ENERGIE -	Yes	Yes	Yes	Yes	Yes	Yes	Yes
VOLTALIS -	Yes	Yes	Yes	Yes	Yes	Yes	Yes
XELAN -	No	Yes	Yes	Yes	Yes	Yes	Yes

On the list
 No
 Yes

Figure 2.14: The List of the NEBEF Operators

Source: RTE's PORTAIL CLIENTS, "Liste des Opérateurs d'Effacement", [On-line], Available: https://clients.rte-france.com/lang/fr/clients_traders_fournisseurs/vie/nebef_operateurs.jsp

2.3 Case of South Korea: Demand Resource Trading Market (DRTM)

2.3.1 Motivations to Introduce DRTM

2.3.1.1 To Increase the Reliability and to Ensure the Security of Supply

Before the introduction of the market-based DR program in December 2014, South Korea faced a series of problems with the reliability and security of electricity supply. For example, on September 15, 2011, due to the lack of the electricity supply to meet the high electricity demand, there was an unprecedented rotating blackout in South Korea, and the state-owned KEPCO unexpectedly cut off the electricity of about 1.6 million households for over four hours. Due to this blackout, there was a huge uproar of the public, and *Jung-gyeong Choi*, the then head of the Ministry of Knowledge Economy, had to resign.

As can be seen in the following Figure of Heatmap of Loads, South Korea in 2016 (Fig. 2.15),^[20] in general in South Korea, the peak load happens in summer and winter during a year, and 9 a.m. to 12 p.m. and 13 p.m. to 18 p.m. during a day. During the summer peak, the high usage of electricity comes from cooling by using air-conditioning devices. However, during the winter peak, the electric appliances for heating are not widely used as much as in France. Also, Figure 2.16 shows the increasing trend of the peak load of South Korea. In summer, 2013, South Korean people had to turn off the air-conditioners at all government and public office buildings when the nation faced a power crisis because several nuclear power plants had to temporarily shut down after the nuclear scandal. These experiences of inconvenience were the direct motivations for the South Korean government to realize the needs to come up with a different measure for the security of the electricity supply and to focus on DR.

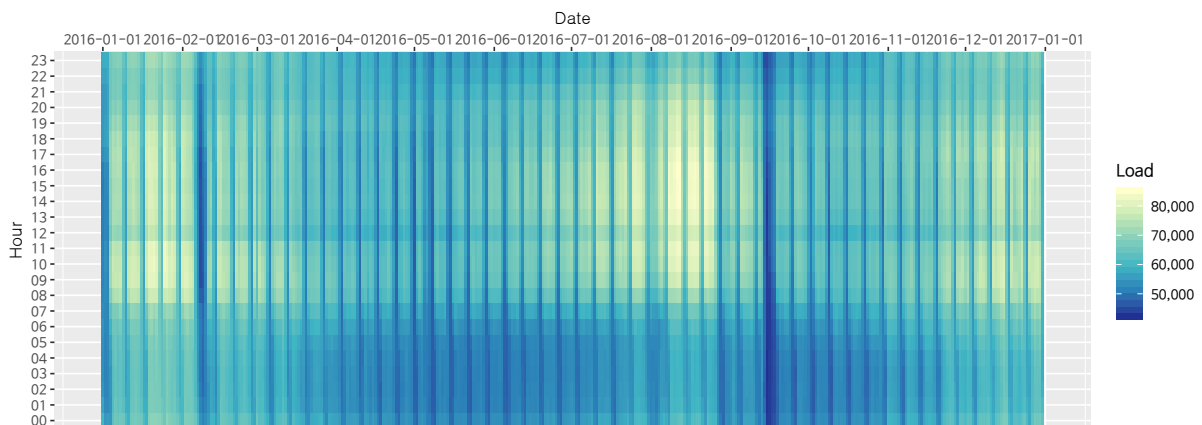


Figure 2.15: Heatmap of Loads, South Korea in 2016 (MW)

Source: “대국민 전력수급현황 공유 시스템” (Public Information Sharing System on Electricity Demand and Supply), KPX, [On-line], Available: <https://openapi.kpx.or.kr/sukub.do#>

Comparison to France: Fig. 2.6

^[20] You can also find the heatmap of loads, South Korea in 2015 (Fig. A.20) in Appendix A: Supplementary Figures & Tables.

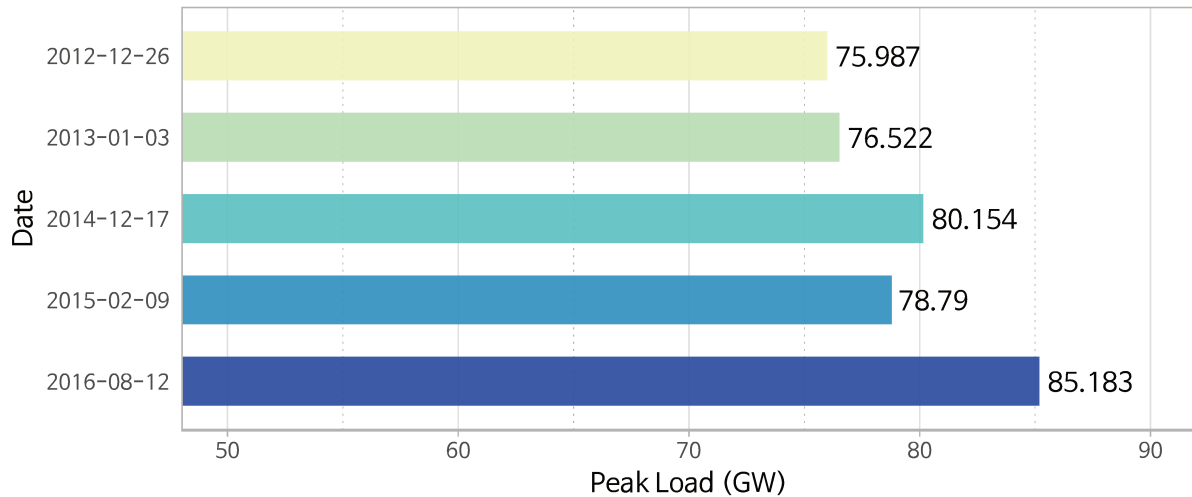


Figure 2.16: Peak Load of South Korea from 2012 to 2016 (GW)

Source: “전력계통운영실적” (Operational Performance of Electric Power System), [Electric Power Statistics Information System \(EPSIS\)](http://epsis.kpx.or.kr/epsisnew/selectEkiBoardList.do?menuId=090120&boardId=003120), [On-line], Available: <http://epsis.kpx.or.kr/epsisnew/selectEkiBoardList.do?menuId=090120&boardId=003120>

Comparison to France: Fig. 2.4

South Korea is one of the most energy-dependent countries because it has very limited natural resources and a very energy-intensive industry structure. Moreover, it is electrically isolated like an island without possible electricity imports from neighboring countries. South Korea generated about 509,016 gigawatt-hours (GW.h) (PRIS (IAEA), 2017b) of total net electricity in 2016 with the total installed capacity of 108.25 GW (Fig. 2.17 and the detailed information in [Appendix A: Supplementary Figures & Tables](#))^[21]—with relatively lower variability [relatively small standard deviation (**Std.Dev**) in Tab. A.4 and shorter interquartile range (**IQR**) in Fig. A.21 in [Appendix A: Supplementary Figures & Tables](#)] of loads compared to France. South Korea’s power generation has increased by an average of 5% annually over the past decade, and [Korea Energy Economics Institute \(KEEI\)](#) expects demand to grow 3.7% annually through 2017, primarily driven by industrial use ([U.S. Energy Information Administration \(EIA\), 2014](#)). In regards to the electricity consumption, in 2012 about 53% of electricity consumption came from industries, 25% from commercial and service enterprises, 14% from the residential sector, and 8% from other sectors like transportation and agriculture, according to KEEI ([U.S. Energy Information Administration \(EIA\), 2014](#)). With electricity consumption growing at a rapid rate and a reliance on fuel imports to meet 98% of its fossil fuel consumption ([U.S. Energy Information Administration \(EIA\), 2018](#)), South Korea is actively promoting DR to help ensure reliability ([Engerati, 2014](#)).

^[21] The LDC of South Korea in 2015 (Fig. A.22) and detailed information are in [Appendix A: Supplementary Figures & Tables](#).

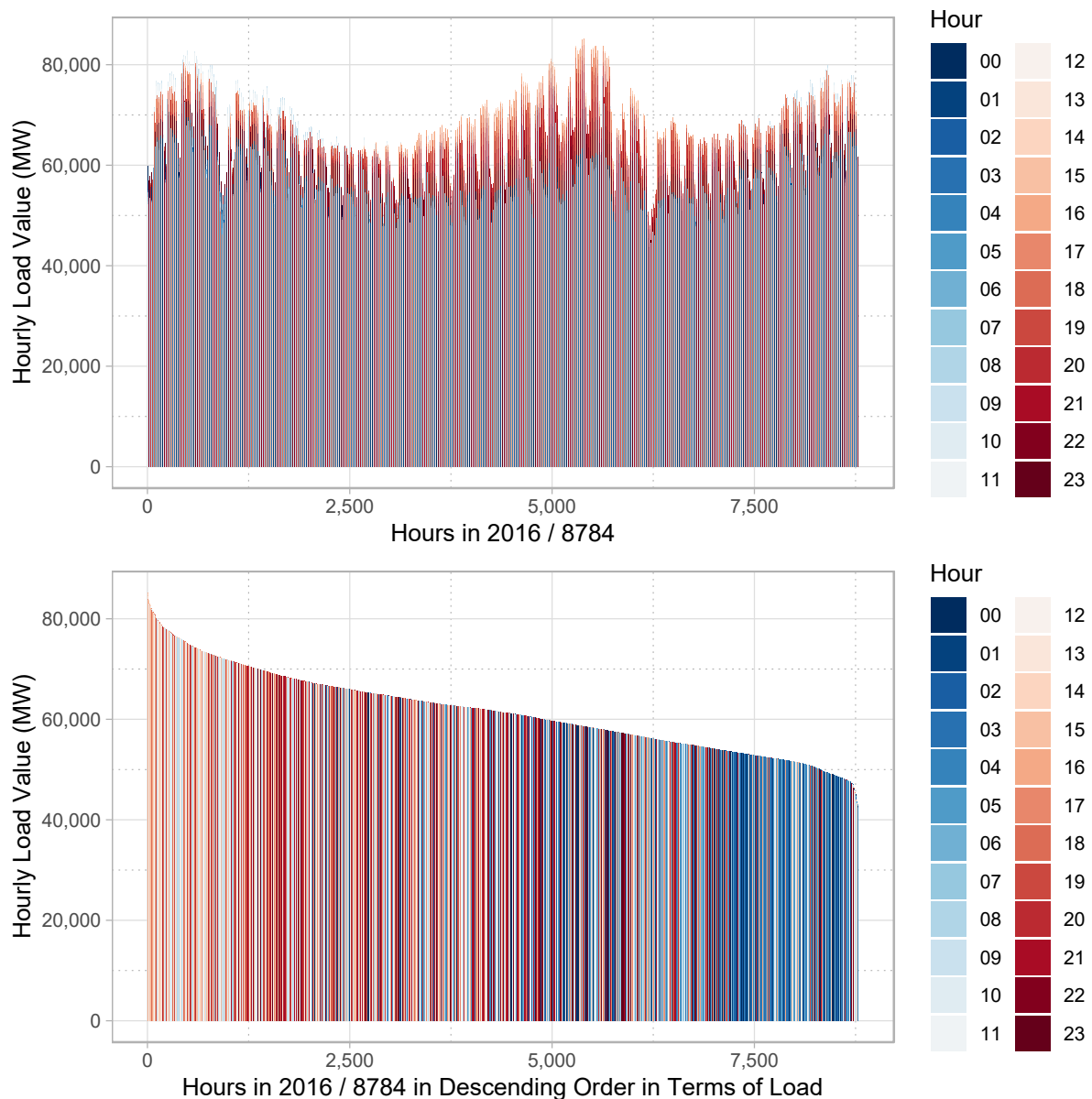


Figure 2.17: Load Duration Curve of South Korea in 2016 (MW)

Source: “대국민 전력수급현황 공유 시스템” (Public Information Sharing System on Electricity Demand and Supply), KPX, [On-line], Available: <https://openapi.kpx.or.kr/sukub.do#>

Comparison to France: Fig. A.19

Despite this huge requirement of energy, it is getting more difficult to meet the demand from the supply-side. In fact, these days the South Korean government is facing the difficulties to search for the available power plant sites for additional capacity and infrastructure both due to the public’s low-level acceptance for the power installations and the enhancement of the environmental regulations. One of the examples is the case of the ‘Miryang Transmission Tower Construction Conflict’ in South Korea. It is the conflict between the local residents in ‘Miryang’ and the KEPCO since 2002, and for the recent years (2012-2014) it has been much more serious drawing public attention. With DR, the government could avoid constructing additional capacity and transmission & distribution infrastructure. In this context, DR and peak consumption management are strategic issues for the South Korean government (Schneider Electric, 2015).

Moreover, to achieve the policy objective to reduce the reliance on nuclear power and fossil fuel imports, the government is promoting greater DR (U.S. Energy Information Administration (EIA), 2014). More recently

the new South Korean government of President Moon set the new energy policy since May 10, 2017. President Moon promised to phase out nuclear power, and the government announced the 'Energy Transition (nuclear phase-out) Roadmap' on October 24, 2017. In the roadmap, the government declared to drop existing plans to build new nuclear power plants and not to extend the lifespan of nuclear reactors. The president also pledged to permanently shut down at least 10 aged coal-fired power plants. Instead of the nuclear power and coal-fired power plants, the government is to increase the share of the RESs from 7% now to 20% by 2030 ['8th Basic Plan for Electricity Supply and Demand (2017–2031)' published on December 29, 2017].

2.3.1.2 To Achieve the Goal of the Environmental Policy

The environmental issue is also one of the reasons for South Korea to be greatly interested in DR. South Korea is seriously concerned about the carbon emissions from electricity generation. The South Korean government puts emphasis on the 'Green Growth' policy, and the government is very well aware of the advantage of DR in terms of the reduction of the CO₂ emissions. In '8th Basic Plan for Electricity Supply and Demand (2017–2031)', the South Korean government is aiming at decreasing the GHG emissions by 26.4% compared to the BAU (business-as-usual) in 2030—the amount of the projecting BAU GHG emissions is 322 million tons, but the amount of the goal in '8th Basic Plan for Electricity Supply and Demand (2017–2031)' is 237 million tons. To that end, the government is going to gradually decrease the coal-based power plants while gradually increasing the share of the RESs, LNG, and alternatives, such as DSM and DR. The following Figure 2.18 indicates the planned capacity in 2017, 2022, and 2030, South Korea.

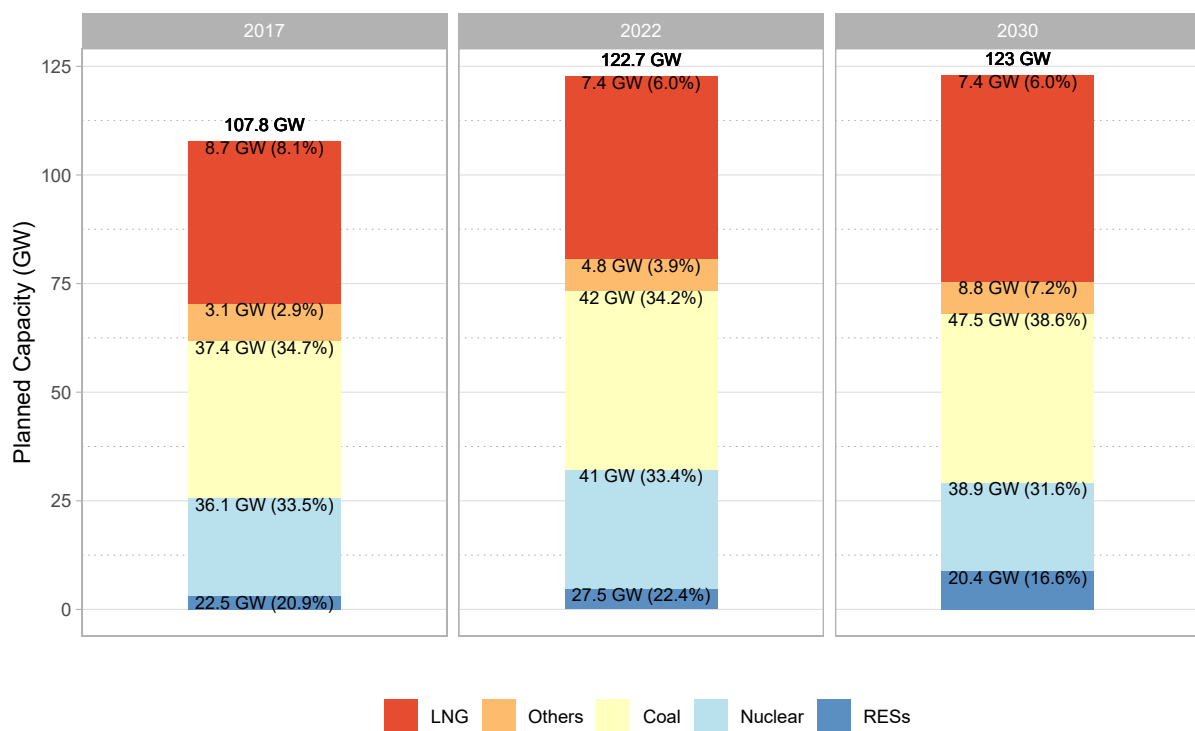


Figure 2.18: Planned Capacity in 2017, 2022, and 2030 (GW)

Source: Ministry of Trade, Industry and Energy, 2017, 8th Basic Plan for Electricity Supply and Demand (2017–2031)

In particular, in order to aggressively promote DR, '8th Basic Plan for Electricity Supply and Demand (2017–2031)' added more measures such as alleviating the barriers to entry for demand-side resources, compulsory

activation under certain conditions, offering more incentives to increase the rate of fulfillment, and planning to introduce 'Demand Resource Trading Market for **All Citizens**'.

There is an additional economic motivation for South Korea. The South Korean government has put DR, i.e. the inauguration of the market for DR, into the 'Creative Economy Initiative' because it could create a new market and jobs encouraging the related industries, which means it can play as a driver for economic growth. The South Korea government published the 'Energy New Industry Creation Measures in Response to Climate Change' (기후변화 대응 에너지 신산업 창출방안) on July 17, 2014, and the DRTM was included as one of the six measures^[22] to create more than 1.2 million jobs and markets that have the value of about 2.08 trillion Korean Won (₩) by 2017.

2.3.2 Recent Performance of DRTM in South Korea

Actually, in the past, the DSM programs were based mainly on load management and EE. Also, it was the government-led DSM programs based on the fund from the government. Table 2.4 shows the size of the fund for DR programs in the past. We can observe that there was quite a big decrease from 2013 to 2014 in terms of the size of the fund. It seems that because the market-based DR program started from December 2014 which replaces the function of the traditional DR programs, the size of the fund for the traditional DR programs significantly decreased.

Table 2.4: The Size of the Fund for DR Program in South Korea from 2012 to 2016

Year	2012	2013	2014	2015	2016
Budget for the fund	386.8	233.9	39.5	40.0	40.0

Unit: trillion Korean Won, ₩

In April 2014, the legislation (revision of 'ELECTRIC UTILITY ACT')^[23] was passed in South Korea allowing DR to participate in its wholesale market, and the recent market-oriented DRM, called the **Demand Resource Trading Market (DRTM)** (수요자원거래시장), was introduced on November 25, 2014 in South Korea. According to **Korea Power Exchange (KPX)**, from the inauguration of the DRTM in November 2014 to May 2015, for the seven months, the amount of the electricity of 142,557 MWh has been saved through the DRTM. At the beginning of South Korean DR program, there were 20 demand-side resources (1,520 MW), 11 DR companies (LAs), and 861 participants (clients of the DR companies). Also, in May 2015, it is expected that about 10 more LAs enter the market, such as Hyosung, GS Power, and so forth. The South Korean government is planning to ensure 1.9 GW of the DR resource by 2017.

As there was a change on the electricity market, the new actors emerged. Recently EnerNOC, an energy intelligence software provider, launched its commercial operation in South Korea (Engerati, 2014). EnerNOC Korea helps many large companies such as LG Chem, Kolon Industries, COEX, and Korea Paper which participate in KPX's DR programs. Also, after the launching of the DRTM in South Korea, Energy Pool and Hyosung, a significant player in the electricity sector and as an LA, signed a 'Business Startup Agreement' to jointly enter into the newly created DR market in January, 2015 (Schneider Electric, 2015).

South Korea's DRTM is just at the beginning stage, so there is a long way to be full-fledged. Until then, it is needed to complement and improve the DR market. In line with this logic, the South Korean government

^[22] In addition to the DRTM, the other five measures are the 'Energy Management Integrated Service Project', 'Independent Micro-grid Project', 'Rental Service of the Photovoltaic Panel', 'Electric Vehicle Charging Service', and 'Project of Effluent Heat Supply from Thermal Power Plant'.

^[23] The english version of this act is [On-line], Available: https://elaw.klri.re.kr/kor_service/lawView.do?hseq=42763&lang=ENG

established a two-stage development roadmap. There would be about two years of the introduction stage in which the government would check out the reliability of demand-side resources and technical requirements to operate the market-based system.

Before the introduction of the DR market, the DR programs were totally separated from the electricity market and were based on the governmental fund. Therefore, it was difficult to measure the effectiveness of the DR programs in the electricity market. With the inauguration of the market, LAs can directly participate in the electricity market the same as the electric power generators.

In terms of the requirements for enrollment, in order to be enrolled as one of the demand-side resources, it should be bigger than 10 MW and smaller than 500 MW consisting of at least 10 customer participants. Also, the demand-side resources should pass the test of [Relative Root Mean Squared Error \(RRMSE\)](#). As the low RRMSE means the regular pattern of the electricity consumption and high reliability, only the demand-side resources whose RRMSE is under 30% can be enrolled. In addition, the demand-side resource needs to go through tests of reliability within two weeks after the initial enrollment and before the peak period in summer and winter.

There are two types of DR in South Korea. The first one is 'Peak Reduction DR' (DR at the Intra-day wholesale market, one-hour-ahead DR). In the past, this 'Peak Reduction DR' was called 'Reliability DR'. Another one is 'Price Reduction DR' (DR at the Day-ahead wholesale market). In the past, this 'Price Reduction DR' was called 'Economic DR'. In the reliability DR program, a participant should follow an order (or call, request) to reduce as much as the enrolled demand-side resources for 2–4 hours within one hour from the order when there is an emergency with under 5 GW reserves. When it comes to the economic DR program, participants can bid for in the Day-ahead market when they think their resources are competitive to those of the power generators.

The payment for the 'Peak Reduction DR' consists of two elements: the base payment and the performance payment. For the base payment, it is paid as much as for the capacity of generators, that is, capacity payment. For the performance payment, it is paid as much as [System Marginal Price \(SMP\)](#) (or maximum variable cost). For the 'Price Reduction DR', it is only paid as much as SMP. In sum, SMP is the remuneration for the 'Price Reduction DR' (Economic DR), and (SMP + Capacity Payment) is the remuneration for the 'Peak Reduction DR' (Reliability DR) in South Korea.

Since the 'Price Reduction DR' (Economic DR) is paid at the level of SMP, there can be issues around it. One of the issues is that the payments for DR might be greater than the decrease in purchasing costs of electricity for retailers, and, as a consequence, there might be a decrease in the retailers' profit. In order to prevent this situation, the NBT, which was introduced earlier in the U.S., 2011 by the FERC Order No. 745 ([Federal Energy Regulatory Commission, 2011](#)), is introduced in South Korean DRTM. The NBTP is the result of the NBT, and LAs cannot bid below this threshold price in South Korean DRTM ([KPX, 2014](#)).

At the beginning of the inauguration of the DRTM in South Korea, the government set the target or possible amount of DR at about below 2% of the total capacity (1.9 GW by 2017). In contrast, the advanced countries have set their optimal amount of DSM much higher at 3–5% of their peak demand. For instance, PJM sets the amount of 6% of the capacity that PJM manages. Regarding the advanced countries' targets, South Korea's target is too conservative despite the fact that the possible size of the demand-side resources is quite limited. The reason why the South Korean government set this relatively small number might be that it is just the beginning stage, so it is difficult to find and ensure reliable demand-side resources. Moreover, there was no experience of running this market-based DR and no enough research on the optimal amount of DR compared to the total capacity or the peak demand. Therefore, on top of the CBA, it is necessary to precisely assess the optimal amount of DR in South Korea based on a 'quantitative analysis', such as econometrics, an economic model, scenario model, or the game theory which could minimize the costs both for demand-side resources and power generation, or maximize the entire utility (social welfare).

Since the inauguration in 2014, in 2014, 2015, and 2016, as the achievement of operating the DRTM, it has reduced totally 632,229 MWh (Tab. 2.5). The total registered capacity of demand resources at the market was

3,886 MW as of 2016,^[24] mainly from the participants of the manufacturing industry (58.8%)—21.6% from the participants of the service industry, 17.4% from the participants of commercial industry, and 2.2% from the participants of the agricultural industry (Fig. 2.19).^[25]

Table 2.5: The Performance of South Korean DRTM in 2014, 2015, and 2016

	2014	2015	2016
Registered Capacity (MW)	1,520	2,889	3,885
Rate of Increase		90.0%	34.5%
Total Reduction (MWh)	4,750	204,852	422,627
Payments (€/₩1,300)	3,196,153	80,560,000	127,316,153
# of Load Aggregators	11	14	14
# of Demand Resources	20	24	30
# of Participants	861	1,519	2,223

Source: “Electric Power Market Statistics in 2016”. KPX, 2017, [On-line], Available: <http://epsis.kpx.or.kr/epsisnew/selectEkifBoardList.do?menuId=090141&boardId=003141>

^[24] You can find the detailed information (Tab. A.5 and Fig. A.23) on the reductions for each month in 2014, 2015, and 2016 as well as the visualization (Fig. A.24) of the registered capacity and the number of participants in 2014, 2015, and 2016 in [Appendix A: Supplementary Figures & Tables](#).

^[25] You can find the table version (Tab. A.6) in [Appendix A: Supplementary Figures & Tables](#).

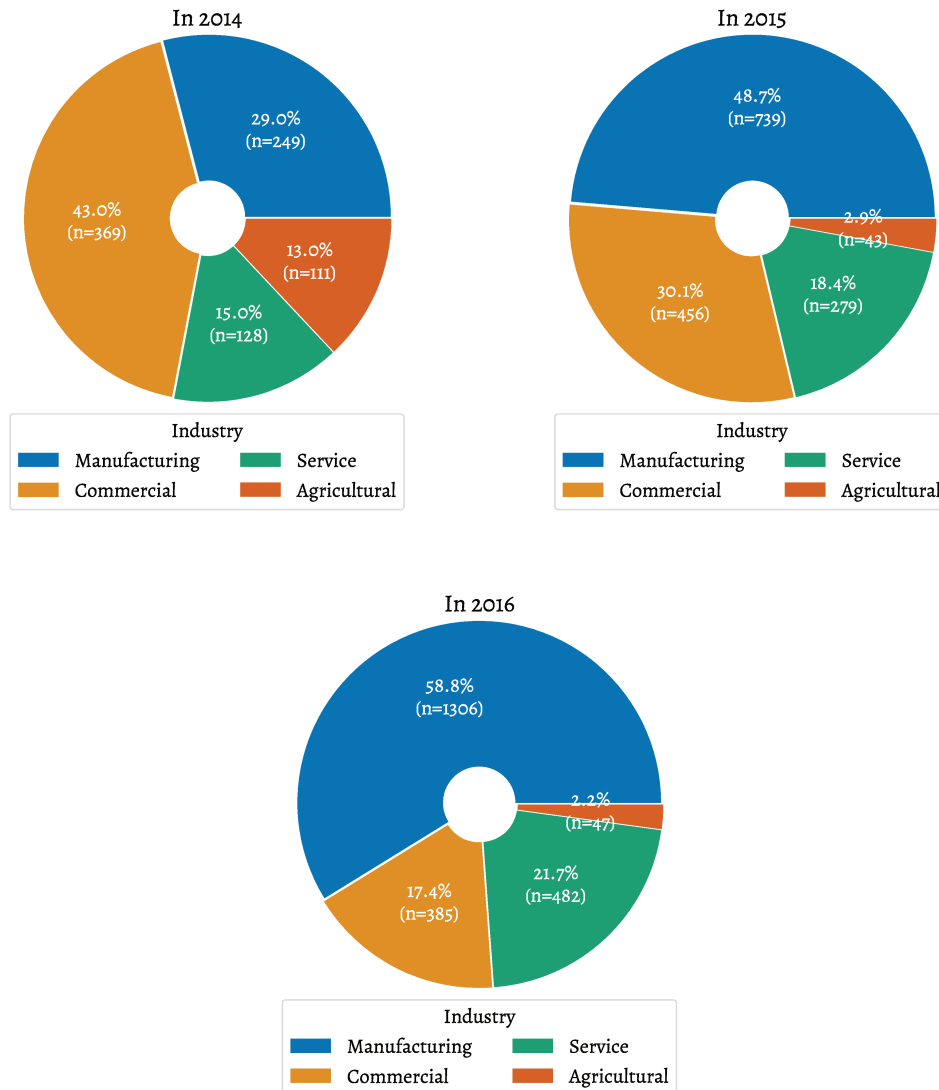


Figure 2.19: The Composition of Participants by Industry

Source: “Electric Power Market Statistics in 2016”, KPX, 2017, [On-line], Available: <http://epsis.kpx.or.kr/epsisnew/selectEkifBoardList.do?menuId=090141&boardId=003141>

Also, Figure 2.20^[26] shows the amount of the payments for the reductions and enrolled capacities at the DRTM for each month in 2014, 2015, and 2016. The figures for the payments in 2014, 2015, and 2016 in Table 2.5 are translated into Euro (€) from the Korean Won (₩). Therefore, from 2014 to 2016 the total reductions and enrolled capacities are worth about 211 million euros (€211,072,306, equivalent to about 274 billion wons, ₩274,448 million wons).

^[26] You can find the detailed numbers of the payments for each month in 2014, 2015 and 2016 in Table A.7 in Appendix A: Supplementary Figures & Tables.

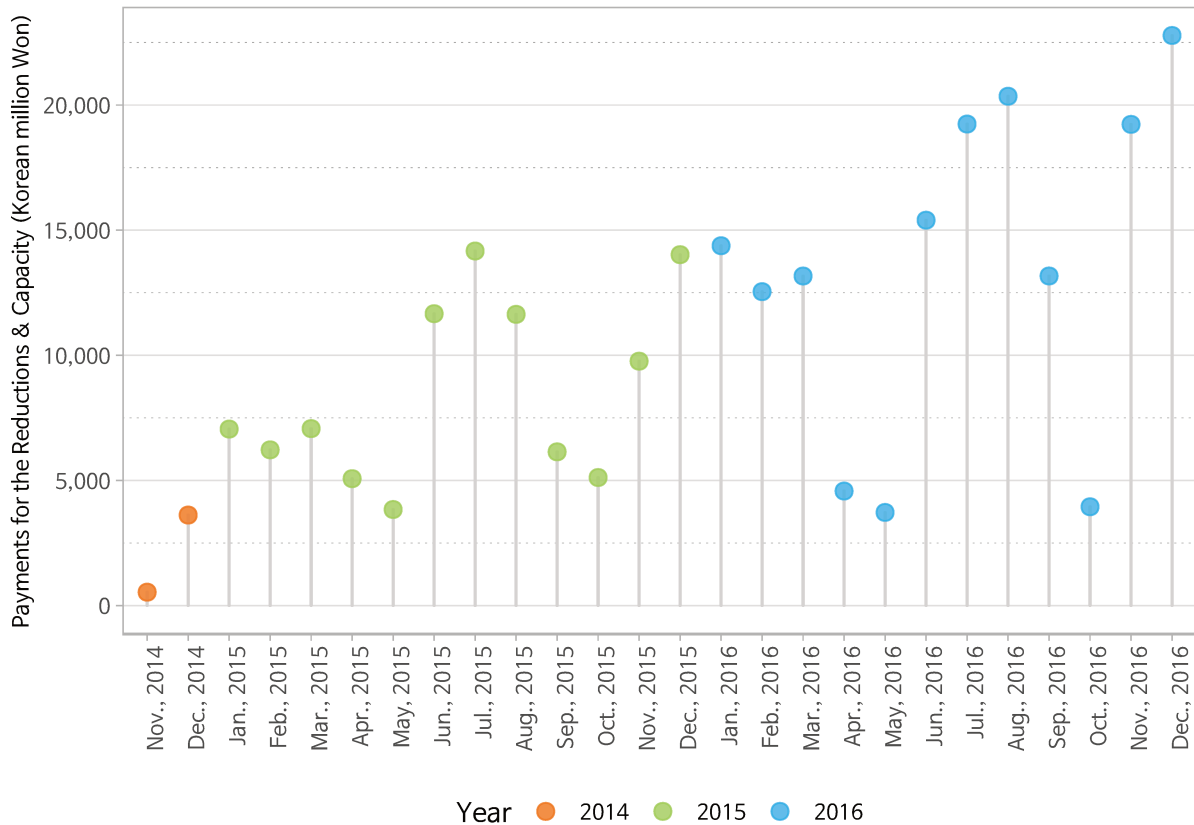


Figure 2.20: The Payments for the Reduction and Capacity at South Korean DRTM in 2014, 2015, and 2016

Source: “Electric Power Market Statistics in 2016”, KPX, 2017, [On-line], Available: <http://epsis.kpx.or.kr/epsisnew/selectEkifBoardList.do?menuId=090141&boardId=003141>

Even though the participation of the demand-side resources in the residential sector has been limited, the South Korean government is now planning to introduce the ‘Demand Resource Trading Market for **All Citizens**’ associated with the project for the widespread of AMI and different types of retail price scheme (ToU Tariff Scheme) starting from 2018. Moreover, from 2020, it will include home appliances and electric vehicles as the subject for demand resources. In addition, it will stabilize the market for demand resources through the ‘automatic demand response system’ which uses communication signals for auto response.

Moreover, recently, there are active discussions to make use of standby generations^[27] in the residential sector as DR resources more progressively (유희덕, 2018). Of course, the South Korean government is also concerned about the emissions of air pollutants, but the use of standby generation is not very limited as long as there is the submission of a document of the facility for air pollutant emission (KPX, 2019, p. 124). On the other hand, there are concerns about the safety risk using these standby generations in DR programs because it seems that safety is not tested yet for many standby generations (문수련, 2018). At the very beginning of the DR program in South Korea, according to the report by KPX in 2015 (KPX, 2015, p. 88), the share of the standby generators in the total demand response resources was about 10.72%. In the report, it estimated the potential of the standby generators as 1/3 of the total DR resources. As of June 2017, the capacity of the

^[27] Unlike the case of South Korea, it seems that the use of standby generations as DR resources is limited in the EU due to the ‘Medium Combustion Plant Directive (MCPD)’ which regulates the Medium Combustion Plants (MCPs), $1 \text{ MWth} \leq x \leq 50 \text{ MWth}$, in terms of air pollutants, such as sulphur dioxide (SO_2), nitrogen oxides (NO_x) (European Commission (EC), 2015).

standby generators was about 27.3 GW (throughout all the sectors) in South Korea (유희덕, 2018).

2.4 Conclusions on Comparisons between France and South Korea

In order to compare the two different DRMs, NEBEF of France and DRTM of South Korea, it is necessary to understand the characteristics of the electricity markets of the two countries first because, without the understanding of it, it would be difficult to understand the DRMs.

First of all, there is a big difference in terms of the structure of the electricity market (Tab. 2.6). In France, there is the day-ahead wholesale market and the intraday wholesale market based on the price bidding via the [European Power Exchange \(EPEX\)](#), which is the platform for trading electricity. In addition to the wholesale markets, it is operating the capacity market, ancillary service market, and reserve market. In contrast, in South Korea, there is only one wholesale market which is a CBP^[28], not based on the price bidding system. It means it lacks the capacity market, ancillary service market, and reserve market, even though there is the ancillary services and reserve programs.

Secondly, there is also a difference regarding the nature of the market: competition and vertical integration. In France, it is not the vertically integrated structure, although EDF is a quasi-monopoly for power generation. The French government is in pursuit of the competition on the market. Contrary to the French case, it is not yet the competition market in South Korea, rather it is a monopolistic market. The KEPCO controls almost all aspects as the main actor in the electricity market except power generation ([U.S. Energy Information Administration \(EIA\), 2014](#)). In terms of the power generation, as a result of the 'Act on the Promotion of Restructuring the Electric Power Industry' in December 2000, KEPCO's electricity generation business was split into six subsidiaries of the power generation companies—Korea Hydro & Nuclear Power Co., Ltd. (KHNP), Korea South-East Power Co., Ltd., Korea Midland Power Co., Ltd., Korea Western Power Co., Ltd., Korea Southern Power Co., Ltd., and Korea East-West Power Co., Ltd. As of June 2018, there are KEPCO's six subsidiaries of the power generation companies (81%) and other eighteen private power generation companies (19%) at the power generation sector. Therefore, we can say that there is a limited competition only in the power generation sector, and there is a monopoly by KEPCO in terms of the power transmission, distribution, sales at the wholesale market and retail market.

The KPX, non-profit, specialized, and membership-based organization with electricity market participants (generators and retailers) as the members, established in 2001 as part of the electricity sector restructuring, serves as the system operator and coordinates the wholesale electric power market by executing the real time dispatch and establishing the basic plan for long term electricity supply and demand ([U.S. Energy Information Administration \(EIA\), 2014](#)).

Now that we understand the differences between the two electricity markets in France and South Korea, we can start the comparison of the two DRMs. Table 2.7 summarises the comparison of the two DRMs in France and South Korea. First of all, in France, the main market-oriented mechanism is NEBEF, which began in December, 2013, and it is the DRTM in South Korea, which started in December, 2014. In France, DR resources can participate in all the operating markets, however, in South Korea, they can participate only in the wholesale market at this moment. The different CBL estimation methods in the two countries will be dealt with in the following Chapter 3. In terms of the remuneration for the DR resources, in South Korea, it is paid at the level of SMP, but in France, it is paid at the level of [SMP – *Versement* (transfer)]. The two different remuneration levels in the two countries may result in the different levels of motivation for the DR participants. This issue will be addressed in Chapter 4 later on.

^[28] At the South Korean CBP wholesale market, the power generation companies can bid only with their 'variable' costs—as indicated by 'Cost-based'. Also, all power transactions should be done at the pooled wholesale market operated by KPX—as indicated by 'Pool'.

Table 2.6: Comparison of the Electricity Market Structure between France and South Korea

	France	South Korea
operating markets		
day-ahead market	o	o
intraday market	o	o
capacity market	o	x
ancillary service market	o	o (service)
reserves market (balancing market)	o	o (service)
platform	EPEX price bidding	KPX a CBP
system operator	RTE (owned by EDF)	KPX
nature of market	competitive, not vertically integrated, highly concentrated,	not very competitive, vertically integrated,
regulator	CRE	MOTIE
main actor	EDF, a quasi-monopoly	KEPCO, a monopoly

Table 2.7: The Comparison of the DR Mechanisms between France and South Korea

	France	South Korea
main DRM	NEBEF	DRTM
main DR operator	RTE	KPX
since	December, 2013 (test phase: Dec. 2013–Dec. 2014)	December, 2014
goals	affordability, sustainability, security of supply, integration of renewable energies,	reliability, security of supply, environmental policy, drivers for economic growth,
possible market(s) for DR participation		
day-ahead market	o	o
intraday market	o (since Jan. 2017)	o
capacity market	o	Non-existence
ancillary service market	o	Non-existence
reserves market (balancing market)	o	Non-existence
CBL method(s)	Day-matching method based on simple average and median	Day-matching method based on WMA & adjustment options
remuneration	(SMP-Transfer)	SMP

2.5 Conclusion

In this Chapter 2, we have reviewed the brief history and the trend of DSM and DR in the U.S. We have found that the U.S. was the first mover since 1970s and now is the leading country in terms of DR [according to the report of Transparency Market Research, recite from (Paterakis et al., 2017, p. 878)]. In Chapter 1, as we have found that one of the barriers to DR was the lack of appropriate regulations on DR in Europe, and unlike Europe, the U.S. could set very well the needed regulations to introduce DSM and DR programs in the electricity market very early on. These clear regulations were the results of the government's strong support and initiatives for DR. As a consequence, these days we can observe the flourishing DR programs and its performances throughout all the major states, such as New England, New York, California, PJM regions, Texas, and so forth. As the U.S. has implemented more DR programs actively, it was possible to accumulate the experiences and to confirm the potential of DR as reliability and flexibility resources.

France, as one of the Member States of the EU, is also emerging as a very active country for DR together with the UK, Belgium, Switzerland, Ireland, and Finland. It seems that the historic peak demand in 2012 was kind of a shock for French people, and since then, they are more concerned about securer measures to guarantee the system reliability and flexibility, especially for the extremely cold winter. The increasing share of RESs, its smooth integration to the power system, and concerns on climate change were also the reasons behind the introduction of the NEBEF mechanism and the full opening of the markets for the demand-side resources. We could find it, the full opening of the markets for the demand-side resources, a strong point of the French electric system.

As we have looked at the evolutions of the NEBEF mechanism, we could observe the trends of improving performances. Moreover, we were able to verify the activation patterns of NEBEF as well as the electricity consumption patterns, i.e. LDC. As we check out the NEBEF indicated LDC, it is possible to conclude that NEBEF should be more activated during the peak periods, especially in winter, in order to achieve the intrinsic objective of DR—that is, reducing the peak loads, and, in turn, ensuring the system reliability, efficiency, affordability, and sustainability. In other words, these observations provided us with some hints for this research that in order to improve the performance of NEBEF, from now on, we need to put more emphasis on the residential sector, load reductions by residential participants should be promoted during the peak periods, which happens usually at 7 p.m., and that to that end, the market design of NEBEF mechanism should be improved in a way that it increases the customers' motivations to participate in it.

When it comes to the DRTM of South Korea, the critical motivation to promote DR and introduce the market-oriented DR mechanism was the reliability and security of supply. Like the experience of the historic peak load in 2012, France, the experiences of unprecedented rotating blackout in 2014 and inconvenience they suffered in extremely hot summers were the direct causes to consider DR as one of the alternative measures to address the unstable and unreliable circumstances in South Korea. Furthermore, the recent government's energy policies on nuclear phase-out, close-down of aged coal-based power plants, more RESs have made the circumstance more suitable for promoting DR.

As we have checked out the heatmap of South Korea's loads, we can expect that DR should play more important roles throughout the entire year, especially during the two peak periods in summer and winter, because there are two peak periods in South Korea, unlike France. We could notice that South Korean DRTM performs very well in terms of the registered capacity and total reductions even though it is a very new mechanism in South Korea. The South Korean government's strong support could be one of the reasons behind this great performance of DRTM. However, we have also noticed that there was no residential participant yet in the composition of the participants in 2014, 2015, and 2016 because until now, the main focus of DRTM is on the industrial and commercial participants, not very encouraging for residential customers. It is expected that as the South Korean government starts the plan of 'Demand Response Trading Market for All Citizens' and ToU tariff scheme for residential customers, there will be active participation of residential customers. This research is preparing for this kind of situation in the very near future in South Korea.

The comparisons of the electricity markets and DR mechanisms between France and South Korea would

provide us with the detailed and fundamental information for the following analyses of CBLs estimation methods, CBAs, Decision-making Analyses, and SAs. Since the demand-side resources are only traded on the wholesale market in South Korea, we cannot analyze the demand-side resources traded on the capacity market, ancillary market, or reserves market in France one-to-one. Therefore, we only focus on the market-oriented DR mechanism and demand-side resources traded on the wholesale market, i.e. NEBEF in France and DRTM in South Korea. We also need to note that even though those two DR mechanisms seem to have similar natures, market-oriented, and resources are traded on the wholesale market, NEBEF and DRTM are not totally based on the same electricity market structures. Therefore, we need to take into account these differences while we conduct the following analyses in Chapter 3 and 4 maintaining the simplicity for the analyses as well.

§Chapter 3

Customer Baseline Load (CBL) Estimation

3.1 Importance of the Accurate CBL Estimation Methods and Difficulties

It is quite important to understand the issues around the concept of ‘CBL’ (Customer Baseline Load or customer baseline).^[1] The CBL means the ‘estimated load’ when there was no direction from the system operator or no effort to reduce (or shift) the electricity consumption—business as usual (IEA, OECD, 2003, p. 127 and p. 128, Figure 8. ‘Baseline Calculation of Demand Response’). Also, Jiang et al. (2015) define baseline as the counterfactual electricity consumption that would have occurred without DSM and is estimated from historical data from the prior year—the following Figure 3.1 shows one demonstrative CBL.

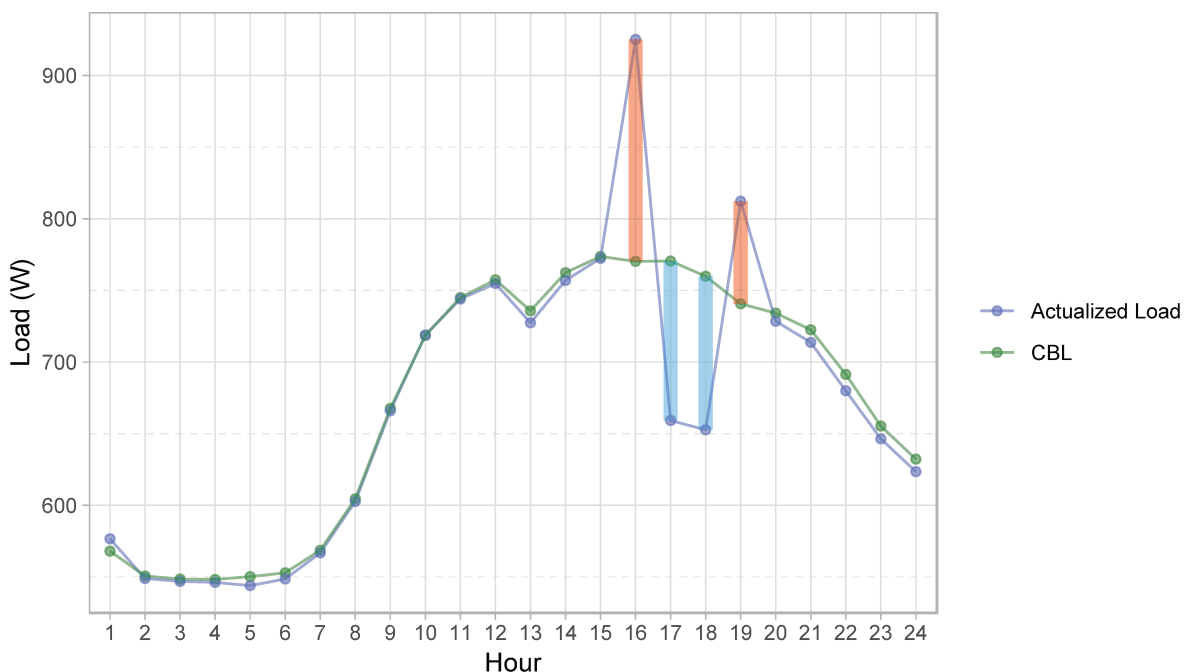


Figure 3.1: One Demonstrative Customer Baseline Load (CBL)

^[1] In an experimental design to figure out the impacts of various DR programs (treatments) on the level and pattern of the consumers’ electricity usage, it is similar to the concept of the ‘unbiased estimate of load’, the ‘reference load’, the ‘counterfactual load’, or the ‘control group’ (the normal consumption patterns without demand response program or actual reduction in electricity consumption). It represents (and is an estimate of) what the usage would have been among treatment group customers had they not been exposed to the treatment. Also, it serves as the foundation for all the following analyses (Electric Power Research Institute (EPRI), 2013, pp. 1–3).

Many economists think that a price-based (implicit) demand response system is an efficient way to reach the socially optimal price-responsive demand (Chao, 2011, p. 69). However, there exist several barriers against the dynamic pricing system: one of them is the difficulty of determining a proper CBL. The concept of the CBL is very important in DSM of electricity. For the electric power generators, it is easy to calculate and remunerate for their electricity production. However, for the demand-side resources, it is hard to calculate the exact amount of electricity reduction. Therefore, determining the CBL is the prerequisite to calculating the payment for the clients and for the CBA.

According to Chao (2011, pp. 71–73), DR depends critically on the choice of CBL. A wrong customer baseline can create distorted incentives and gaming opportunities. Chao (2011, p. 75) suggested a ‘contractual customer baseline approach’ rather than an administratively determined customer baseline which could undermine the efficiency of demand response programs and cause the double payment issue. In practice, it is interesting to observe that when NYISO in the U.S. changed the method to calculate and set the CBL, and it resulted in more tightened criteria for qualification, there were fewer demand response resources registered as Special Case Resources (SCRs) (Federal Energy Regulatory Commission, 2014, p. 11).^[2]

Despite the importance of the CBL, it is quite difficult to properly construct a CBL for each participant in a DR program, especially for residential customers because it is difficult to measure customer’s individual, subjective, and characteristic load pattern. Basically, the methods to estimate CBLs are based on the previous load patterns of customers by using some formulas, therefore, it cannot be perfect itself.

There will be adverse effects if there are either underestimation or overestimation of CBL (Park et al., 2015). If there is an underestimation of CBL, participants’ actual reduction will be underestimated, and participants’ efforts to reduce loads are not well appreciated. Therefore the proper payment or incentives are not given to them. In the end, it will decrease their motivations to participate in the DR program, as a result, they would cancel the contract with the LA and exit from the market (KPX, 2014, p. 122). If there is the overestimation of CBL, the DR program operator needs to pay more remuneration than the actual amount for the LAs (and in the end, for the participants), and it will decrease the motivation of the DR program operator to run the DR program.

Due to these imperfect methods to establish CBLs, there are motivations for participants to manipulate their daily load patterns. Jiang et al. (2015) are well aware of the fact that the baseline is subject to manipulation because DR participants have a greater awareness of their facilities than the regulatory agencies responsible for estimating the baseline (it is about the information asymmetry). DR participants are likely to manipulate the baseline in order to receive greater financial compensation. An intentionally inflated baseline is shown to result in a different resources dispatch, high system costs, and unachievable social welfare.

Moreover, a CBL of a client who participates in the demand response market should have the regularity, which means, it should demonstrate the same or flat pattern over time. If it does not have a regularity, it means it can change any time, so we can think that it is extremely difficult to establish a reliable CBL for the evaluation of the actual load reduction. That kind of client cannot participate in the demand response market. We can use the index of RRMSE to calculate the degree of how regular the pattern of the electricity consumption is.

^[2] The FERC added one more factor accounting for this decrease in the demand response resource registered as SCR that relatively low capacity prices in NYISO in recent years may have also contributed to less participation in it (Federal Energy Regulatory Commission, 2014, p. 11).

3.2 Methods to Calculate Customer Baseline Load

There are several terms related to CBL. The DR *event day* means the day in which there is a call or order from the system operator to activate the DR program, and as a result, there will be an actual reduction of electricity consumption. The *similar non-event days* means the days that are used in the computation of CBL, and it does not include the previous DR event days. The 10 or 20 *reference days* are the candidates for the similar non-event days. To choose the reference days, the prior DR event days, holidays, weekends will be excluded, and only ordinary working week-days are included. Also, for the reference days, there is an 'option of abnormal working days' with which we exclude the days that are significantly different from the ordinary electricity consumption pattern because of some malfunctions of equipment, the special anniversary days of a factory or company, or temporary adjustment of the quantity of production. If it is under 75% or over 125% of the average electricity consumption, those days will be excluded (KPX, 2019, Appendix 28, pp. 528–530).

In general, we can categorize the methods (or techniques) of establishing CBL into two: the conventional and unconventional techniques. For the conventional techniques, again, there are roughly two techniques: day matching (or match) methods and the method of regression analysis^[3]. For the unconventional methods, there is a data-driven baseline load estimation method, such as the data mining approach (Park et al., 2014, 2015).

The basic idea of day matching methods is that we take a short historical period close to the DR event day and calculate CBL (CBL^{avg}) by simply averaging the data of the previous non-event days [first choosing reference days, and then among reference days choosing similar non-event days for the calculation]. For day matching methods, there are also various methods depending on how many days you consider as reference days and similar non-event days, how you exclude some days from reference days to select similar non-event days, how you reflect the changes in the temperature of the DR event day [Weather Sensitivity Adjustment (WSA) option],^[4] how you reflect the changes of the electricity consumption pattern or amount [Symmetric Additive Adjustment (SAA) option]^[5] of the DR event day, what kind of options you allow for the participants, and so forth. For example, '3 Days Types', '7 Days Types', 'Average 6/10 (=Mid 6/10)', 'Average 6/10+SAA option', 'Max 4/5', 'Max 4/5+SAA option', 'High 3/10', 'High 3/10+SAA option', and so forth. As I enumerated some of them, there are so many methods for the day matching, therefore, it is better to explain the examples in reality.

In the U.S., the CAISO uses the method called the 'Baseline Type I' of the North American Energy Standards Board (NAESB)'s Measurement and Verification Standard (KEMA, 2011). Ten similar non-event days are used for the 'Baseline Type I'. The ISO-NE uses five similar non-event days prior to the DR event day. PJM used to use the high four days out of five reference days in order to calculate the baseline, however, it changed the way where PJM suggests nine basic CBL methods^[6] and the LAs can choose the best methods for their clients (participants) (KPX, 2014, pp. 125–126). It changed again, and now there are different default methodologies depending on the specific program and type of DR product (Rossetto, 2018; PJM Interconnection (PJM), 2019). In South Korea, in the past, like PJM, KPX used to use the four most energy-intensive days among the last five days, but recently it changed the methods, and now KPX allows LAs to choose one between 'Max (4/5)' and 'Mid (6/10)'^[7] as well as the option of SAA (KPX, 2019, Appendix 28, pp. 528–530). Between the two CBL

^[3] For the research that utilized the regression analysis to establish CBL, please refer to the followings: Woo and Herter (2006); Braithwait et al. (2010); Coughlin et al. (2008); Sharifi et al. (2016)

^[4] WSA is one of the options for the modification of the calculated CBL considering the impact of weather conditions on power consumption.

^[5] SAA is one of the options for the modification of the calculated CBL considering the difference in the electricity consumption pattern.

^[6] For the nine basic CBL methods, there are '3 Days Types', '3 Days Types with SAA', '3 Days Types with WSA', '7 Days Types', '7 Days Types with SAA', 'Max base load', 'Metered generation', 'Same day (3+2)', 'Match day (3 day average)'

^[7] It is generally accepted that the duration of approximately 10 days reasonably represents the expected consumption for normal operation (Park et al., 2015, p. 10250).

estimation methods utilized in South Korea, in this study, 'Mid (6/10)' will be examined.

As conventional and typical methods, day matching methods are often utilized in reality because it is relatively simple compared to other more complex methods. Therefore, it is quite easy for the participants to understand the concept of CBL and the process of its calculation. Moreover, many of the previous research on CBL have found that this typical and conventional method has almost the same accuracy compared to others. In South Korea, as practical research, Won et al. (2009, p. 1) conducted a case study analysis for the real South Korean customers and concluded that the simple statistical method is better than the complex regression method to determine a customer baseline for very random loads.

As we think that good CBL methods should satisfy all the three criteria, that is, *accuracy*, *simplicity*, and *integrity*, we cannot say that more complex regression analysis method and other unconventional methods are better than day matching methods. The more the CBL methods are complex, the more obstacles for the consumers to participate in DR programs.^[8] KEMA, a global energy consulting company headquartered in Arnhem, Netherlands, is also very well aware of it and recommends us to use various methods which are most suitable for the electricity consumption patterns of participants (KPX, 2014, p. 125). KEMA gives us the advice that since the accuracies of the methods are similar to each other, we need to go over comprehensively taking into account simplicity and the operation costs to calculate CBL as well as the accuracy of the prediction of electricity consumption patterns.

On top of the basic day matching methods with a simple average, there is one method that uses the **Weighted Moving Average (WMA)**. This method gives more weights to the more recent days to the DR event day (Wi et al., 2009). If we give the same weights to the similar non-event days to calculate CBL, we cannot reflect the recent changes in the data such as the recent dramatical temperature changes or socio- and economic-events. Because there is no explicit rule for the specific values of the weights in practice, the weights seem to be ad-hoc or arbitrary. Therefore, it is important to keep in mind the principle that loads of recent days have heavier weights.

$$CBL_{d,t} = \sum_{i=1}^n (\omega_i \times \ell_{d-i,t}) \quad (3.1)$$

where,

$$\left\{ \begin{array}{l} CBL_{d,t} : \text{customer baseline load for the DR event day, } d, \text{ at the event time, } t, \\ \quad \quad \quad d \in D = \{1, 2, \dots, 365\}, t \in T = \{1, 2, \dots, 24\}, \\ \quad \quad \quad \sum_{i=1}^n (\omega_i \times \ell_{d-i,t}) \\ \omega_i : \text{weights for } i^{\text{th}} \text{ day before the DR event day,} \\ \quad \quad \quad \sum_{i=1}^n \omega_i = 1, i = 1, 2, \dots, n. \\ \quad \quad \quad \omega_1 > \omega_2 > \dots > \omega_{n-1} > \omega_n \\ \ell_{d-i,t} : \text{actual load at the time slot of } t \text{ and on the day of } (d-i) \text{ (} i^{\text{th}} \text{ day before the DR} \\ \quad \quad \quad \text{event day),} \\ n : \text{the total number of the similar non-event days that are used for the calcula-} \\ \quad \quad \quad \text{tion. For example, if 6 similar non-event days are utilized for the 'Mid 6/10'} \\ \quad \quad \quad \text{CBL estimation method, } n \text{ is 6. It is different from the day index, } d \text{ in a year.} \end{array} \right.$$

^[8] This argument could be controversial because it depends on the extent to which CBL estimation methods are explicitly embedded in consumers' decision-making. Consumers may not care very much about CBL estimation methods as long as it is accurate enough to correctly estimate their reductions. However, if there are consumers who care about how their CBLs are estimated, it is a problem if it is too complex to explain it to them.

3.3 To Assess the Estimated CBL

After establishing the CBL, we need to assess the accuracy of the estimated CBL.^[9] There are three mainly used techniques: **Average Relative Error (ARE)**, **Mean Absolute Percentage Error (MAPE)** and **RRMSE**. In general, to verify the accuracy of the calculated CBL we can calculate the estimation error by comparing the actual electricity consumption and the estimated CBL (Park et al., 2015, p. 10252):

$$\begin{aligned} \text{estimation error (\%)} &= \frac{|\text{CBL} - (\text{actual electricity load})|}{(\text{actual electricity load})} \times 100 \\ &= \frac{|\text{CBL}_{d,t} - \ell_{d,t}|}{\ell_{d,t}} \times 100 \end{aligned} \quad (3.2)$$

ARE is the average estimation error for all the verified time splots of the CBL. If ARE is close to 0 (zero), it means there is a high accuracy of the estimated CBL. If it is greater than 0, it means the overestimated CBL, and if it is less than 0, it means underestimated CBL.

$$\text{ARE} = \frac{1}{(t_e - t_s) + 1} \sum_{t=t_s}^{t_e} \frac{\text{CBL}_{d,t} - \ell_{d,t}}{\ell_{d,t}} \quad (3.3)$$

where,

$$\left\{ \begin{array}{ll} (t_e - t_s) + 1 & : \text{DR event time intervals,} \\ t_s & : \text{DR event starting time,} \\ t_e & : \text{DR event ending time,} \\ \text{CBL}_{d,t} & : \text{customer baseline load for the DR event day, } d, \text{ at the event time, } t, \\ & d \in D = \{1, 2, \dots, 365\}, t \in T = \{1, 2, \dots, 24\}, \\ & \sum_{i=1}^n (\omega_i \times \ell_{d-i,t}) \\ \ell_{d,t} & : \text{actual load at the time slot } t \text{ and on the day of } d, \\ & d \in D = \{1, 2, \dots, 366\}, t \in T = \{1, 2, \dots, 24\}. \end{array} \right.$$

MAPE is almost the same with ARE except that it uses the absolute value of the difference between the CBL and the actual electricity consumption.

$$\text{MAPE} = \frac{1}{(t_e - t_s) + 1} \sum_{t=t_s}^{t_e} \frac{|\text{CBL}_{d,t} - \ell_{d,t}|}{\ell_{d,t}} \times 100 \quad (3.4)$$

where,

$$\left\{ \begin{array}{ll} (t_e - t_s) + 1 & : \text{DR event time intervals,} \\ t_s & : \text{DR event starting time,} \\ t_e & : \text{DR event ending time,} \\ \text{CBL}_{d,t} & : \text{the estimated CBL during DR event period,} \\ \ell_{d,t} & : \text{actual load at the time slot } t \text{ and on the day of } d, \\ & d \in D = \{1, 2, \dots, 366\}, t \in T = \{1, 2, \dots, 24\}. \end{array} \right.$$

^[9] Note that we establish the CBL targeting at the DR event day, but for assessing the estimation method for CBL it should be done before the DR event day. Therefore, for the assessment of the CBL estimation method, we do not take into account the DR event day as we excluded the previous DR event days for similar non-event days.

RRMSE is more complex than the previous techniques to verify the accuracy of the estimated CBL. The smaller RRMSE, the better. As we have seen that in Subsection 2.3.2, RRMSE is used as the criteria to assess the estimated CBL of the participants in South Korea (KPX, 2019, pp. 532–533).

$$\text{RRMSE} = \sqrt{\frac{1}{(t_e - t_s) + 1} \sum_{t=t_s}^{t_e} (\text{CBL}_{d,t} - \ell_{d,t})^2} \times \frac{1}{\frac{1}{(t_e - t_s) + 1} \sum_{t=t_s}^{t_e} \ell_{d,t}} \times 100 \quad (3.5)$$

where,

$$\left\{ \begin{array}{ll} (t_e - t_s) + 1 & : \text{DR event time intervals,} \\ t_s & : \text{DR event starting time,} \\ t_e & : \text{DR event ending time,} \\ \text{CBL}_{d,t} & : \text{the estimated CBL during DR event period,} \\ \ell_{d,t} & : \text{actual load at the time slot } t \text{ and on the day of } d, \\ & d \in D = \{1, 2, \dots, 366\}, t \in T = \{1, 2, \dots, 24\}. \end{array} \right.$$

Root Mean Square Error (RMSE) is at the place of the numerator of RRMSE.

$$\text{RMSE} = \sqrt{\frac{1}{(t_e - t_s) + 1} \sum_{t=t_s}^{t_e} (\text{CBL}_{d,t} - \ell_{d,t})^2} \quad (3.6)$$

where,

$$\left\{ \begin{array}{ll} (t_e - t_s) + 1 & : \text{DR event time intervals,} \\ t_s & : \text{DR event starting time,} \\ t_e & : \text{DR event ending time,} \\ \text{CBL}_{d,t} & : \text{the estimated CBL during DR event period,} \\ \ell_{d,t} & : \text{actual load at the time slot } t \text{ and on the day of } d, \\ & d \in D = \{1, 2, \dots, 366\}, t \in T = \{1, 2, \dots, 24\}. \end{array} \right.$$

In this section, we have checked out possible statistical techniques to assess estimated CBLs, but in this research, we are going to use only two statistical techniques, MAPE and RRMSE. As we have seen that there is no significant difference between MAPE and RRMSE, both two statistical techniques will be utilized with the experimental purpose. If we need to choose only one as the criteria to assess estimated CBLs, RRMSE will be chosen that is used in South Korea at this moment and more precise.

3.4 CBL for an Average Household in South Korea

The focus date for the analysis is the peak day that happened on Friday, August 12, 2016 (Fig. 2.16). Therefore, let us assume that the event time of the event day is from 17:00 to 19:00 (one block consisting of two-time slots, 17 and 18) on Friday, August 12, 2016.

In order to obtain the electricity load (consumption) profile of an average household^[10] for a certain period (non-event similar days), we can scale down the aggregate load profile using the information on the 'proportion of residential sector to the total load' and the 'total number of the contracted household'. In fact, the load pattern of the aggregate load and the effective load pattern of the residential sector are obviously different. However, under the circumstance in which the real hourly load data for the residential sector is not available, using a rescaled load profile may also be helpful to draw some insight and implications throughout the analysis.

In 2016, the proportion of the residential sector to the total load was about 13.3%, and the total number of the contracted households was about 14.6 million (14,626,290).^[11] The following Figure 3.2, 3.3, 3.4, and Table 3.1) show the number of residential customers, total consumption, average consumption, and list of the top 5 regions in the residential sector by region in 2016, South Korea. Examining these figures, we can identify the possible target area or group in order to exploit the maximum level of the DR mechanism.

^[10] As the research on DR in the non-residential sector (Grünwald and Torriti, 2013) shows that there is very significant heterogeneity in certain commercial and industrial users in terms of typical average loads, we could expect that in the residential sector it could also be quite challenging to define a profile of an 'average household'. In order to specify the profile of an 'average household', we need more granular datasets and an in-depth study taking into account a number of socio-demographic factors. Here, we are not trying to challenge that. Instead, just in order to establish CBLs and to assess the CBL estimation methods, we need a load profile whose size or scale is reasonably similar to that of an average household.

^[11] In 2015, it was 12.9% and 14,419,050. For the detailed information on the electricity consumption share by usage or sector, the number of clients by usage and area, please, refer to the site of "Electricity Big Data Center" operated by KEPCO, [On-line], Available: <https://home.kepco.co.kr/kepco/BD/BDBAPP001/BDBAPP001.do?menuCd=FN33020101>; KEPCO, 2018, STATISTICS OF ELECTRIC POWER IN KOREA, [On-line], Available: <https://goo.gl/fDxG1Y>

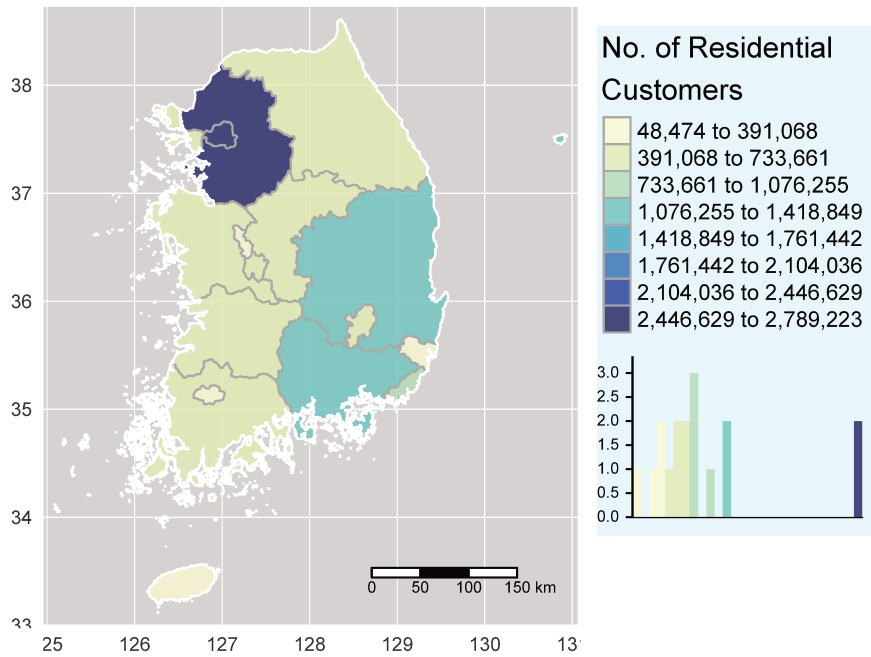


Figure 3.2: The Number of Residential Customers by Region, 2016 in South Korea

Source: “Electricity Big Data Center” operated by KEPCO, [On-line], Available: <https://home.kepco.co.kr/kepco/BD/BDBAPP004/BDBAPP004.do?menuCd=FN33020104>

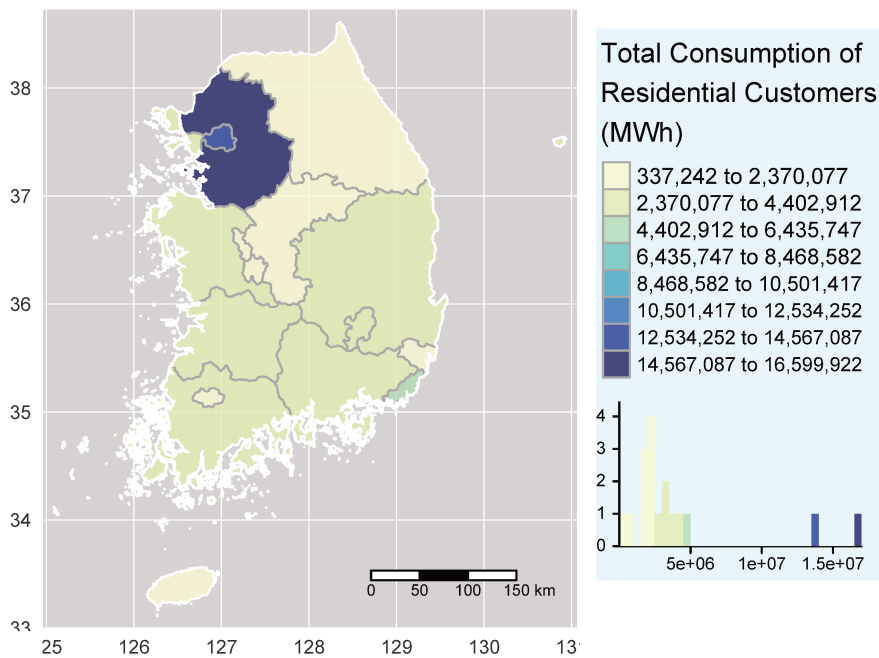


Figure 3.3: The Total Consumption of Residential Customers by Region, 2016 in South Korea (MWh)

Source: “Electricity Big Data Center” operated by KEPCO, [On-line], Available: <https://home.kepco.co.kr/kepco/BD/BDBAPP004/BDBAPP004.do?menuCd=FN33020104>

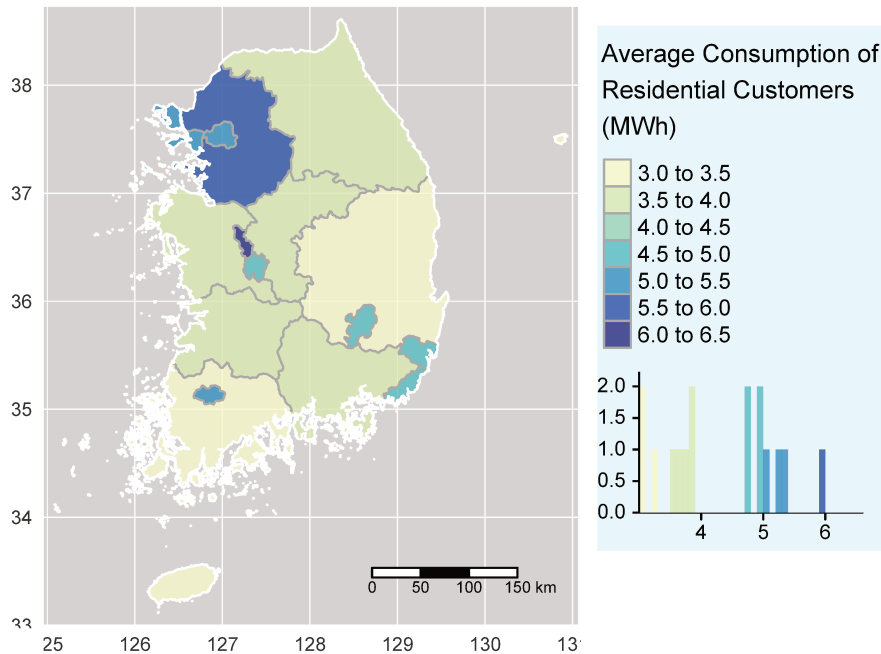


Figure 3.4: The Average Consumption of Residential Customers by Region, 2016 in South Korea (MWh)

Source: “Electricity Big Data Center” operated by KEPCO, [On-line], Available: <https://home.kepco.co.kr/kepco/BD/BDBAPP004/BDBAPP004.do?menuCd=FN33020104>

Table 3.1: The Top 5 Regions in terms of Number, Total Consumption, and Average Consumption in Residential Sector in South Korea

Rank	Region	No. Sites	Region	Total Conso. (MWh)	Region	Avg. Conso. (MWh)
1	Gyeonggi -do	2,789,223	Gyeonggi -do	16,599,922	Sejong	6.96
2	Seoul	2,718,481	Seoul	13,612,456	Gyeonggi -do	5.95
3	Gyeongsangnam -do	1,133,686	Busan	4,640,944	Incheon	5.39
4	Gyeongsangbuk -do	1,121,299	Gyeongsangnam -do	4,384,578	Gwangju	5.26
5	Busan	944,624	Incheon	391,532	Seoul	5.01

Source: “Electricity Big Data Center” operated by KEPCO, [On-line], Available: <https://home.kepco.co.kr/kepco/BD/BDBAPP004/BDBAPP004.do?menuCd=FN33020104>

Therefore, we can obtain the rescaled load profile of an average household (W) from the aggregate load (MW)

like the following:

$$\mathbf{L}_{366 \times 24}^{\text{agg.}} = \begin{matrix} & \begin{matrix} 1 & 2 & \dots & 24 \end{matrix} \\ \begin{matrix} 1 \\ 2 \\ \vdots \\ 366 \end{matrix} & \begin{pmatrix} \ell_{1,1} & \ell_{1,2} & \dots & \ell_{1,24} \\ \ell_{2,1} & \ell_{2,2} & \dots & \ell_{2,24} \\ \vdots & \vdots & \ddots & \vdots \\ \ell_{366,1} & \ell_{366,2} & \dots & \ell_{366,24} \end{pmatrix} \end{matrix} \quad (3.7)$$

$$\mathbf{L}_{366 \times 24}^{\text{avg.res.}} = \frac{13.3}{100} \times \frac{1}{14,626,290} \times 1,000 \times 1,000 \times \mathbf{L}_{366 \times 24}^{\text{agg.}} \quad (3.8)$$

where,

$$\left\{ \begin{array}{l} \mathbf{L}_{366 \times 24}^{\text{agg.}} : \text{ a matrix of aggregate loads, } 366 \text{ rows} \times 24 \text{ columns, in 2016 (there were 366} \\ \text{days in 2016),} \\ \mathbf{L}_{366 \times 24}^{\text{avg.res.}} : \text{ a matrix of rescaled loads of an average household in (W), } 366 \text{ rows} \times 24 \\ \text{columns,} \\ \ell_{d,t} : \text{ actual load at the time slot } t \text{ and on the day of } d, \\ \text{ } d \in D = \{1, 2, \dots, 366\}, t \in T = \{1, 2, \dots, 24\}. \end{array} \right.$$

In South Korea, KPX uses the weighted moving average method based on the day matching method (Park et al., 2015). Among the 10 reference days, the highest two days and lowest two days are excluded in terms of the amount of the total electricity consumption [therefore, it is Mid(6/10)]. The weights are 0.25, 0.20, 0.15, 0.15, 0.15, and 0.10 for the most recent days respectively. It means putting more emphasis on the recent day's energy consumption by assigning high weight.

$$\text{CBL}_{d,t}^6 = \sum_{i=1}^6 \omega_i \cdot \ell_{d-i,t} \quad (3.9)$$

where,

$$\left\{ \begin{array}{l} \text{CBL}_{d,t}^6 : \text{ CBL at the time of } t, \text{ and on the day of } d, \text{ based on the Mid(6/10),} \\ \omega_i : \text{ the weight for } i^{\text{th}} \text{ day before the DR event day,} \\ \ell_{d-i,t} : \text{ the load (demand) at the time of } t, \text{ and on the day of } (d-i) \text{ (} i^{\text{th}} \text{ day before the} \\ \text{DR event day).} \end{array} \right.$$

$$\begin{aligned} \text{CBL}^{\text{WMA}} &= \mathbf{w}^T \cdot \mathbf{S}^6 \\ &= \left(\omega_6 \quad \dots \quad \omega_1 \right) \cdot \begin{pmatrix} \ell_{d-6,1} & \ell_{d-6,2} & \dots & \ell_{d-6,24} \\ \ell_{d-5,1} & \ell_{d-5,2} & \dots & \ell_{d-5,24} \\ \vdots & \vdots & \ddots & \vdots \\ \ell_{d-1,1} & \ell_{d-1,2} & \dots & \ell_{d-1,24} \end{pmatrix} \\ &= \left(\text{CBL}_1^{\text{WMA}} \quad \text{CBL}_2^{\text{WMA}} \quad \dots \quad \text{CBL}_{24}^{\text{WMA}} \right) \end{aligned} \quad (3.10)$$

where,

$$\left\{ \begin{array}{l} \mathbf{CBL}^{\text{WMA}} : \text{a vector of CBL which is calculated with the weighted moving average method,} \\ \boldsymbol{\omega}^{\text{T}} : \text{a transposed vector of the weights for } i^{\text{th}} \text{ day before the DR event day,} \\ \mathbf{S}^6 : \text{a matrix of the similar non-event 6 days,} \\ \ell_{d-i,t} : \text{actual load at the time slot of } t \text{ and on the day of } (d-i) \text{ (} i^{\text{th}} \text{ day before the DR event day).} \end{array} \right.$$

$$\mathbf{w}^{\text{T}} = \left(\omega_6 \quad \dots \quad \omega_1 \right) = \left(0.10 \quad 0.15 \quad 0.15 \quad 0.15 \quad 0.20 \quad 0.25 \right) \quad (3.11)$$

Once we calculate the CBL by using the weighted moving average and the day matching method, it is necessary to adjust the CBL reflecting the difference between the estimated CBL and the actual electricity consumption prior to the DR event time. We can adjust the CBL proportionally or additively. First, the following is the proportionally adjusted CBL:^[12]

$$\text{Updated } \mathbf{CBL}_{d,t}^{\text{PAC}} = \text{Proportional Adjustment Coefficient} \times \mathbf{CBL}_{d,t}^{\text{WMA}} \quad (3.12)$$

For the **Proportional Adjustment Coefficient (PAC)** (or adjustment factor), we use the proportion of the average actual electricity load at the time of $t - 1$ and $t - 2$ on the DR event day over the average CBL at the time of $t - 1$ and $t - 2$ on the DR event day.^[13]

$$\text{PAC} = \frac{(\ell_{d,t-1} + \ell_{d,t-2})}{2} \div \frac{(\mathbf{CBL}_{d,t-1}^{\text{WMA}} + \mathbf{CBL}_{d,t-2}^{\text{WMA}})}{2} \quad (3.13)$$

$$\begin{aligned} \mathbf{CBL}^{\text{WMA}} \cdot \text{PAC} &= \text{PAC} \cdot \mathbf{CBL}^{\text{WMA}} \\ &= \text{PAC} \cdot \left(\mathbf{CBL}_1^{\text{WMA}} \quad \mathbf{CBL}_2^{\text{WMA}} \quad \dots \quad \mathbf{CBL}_{24}^{\text{WMA}} \right) \end{aligned} \quad (3.14)$$

where,

$$\left\{ \begin{array}{l} \mathbf{CBL}^{\text{WMA}} \cdot \text{PAC} : \text{a vector of proportionally adjusted CBL,} \\ \text{PAC} : \text{Proportional Adjustment Coefficient for the weighted moving average method,} \\ \ell_{d,t-1} : \text{the load (demand) at the time of } t-1, \text{ and on the day of } (d), \\ \ell_{d,t-2} : \text{the load (demand) at the time of } t-2, \text{ and on the day of } (d), \\ \mathbf{CBL}_{d,t-1} : \text{the estimated CBL at the time of } t-1, \text{ and on the day of } (d), \\ \mathbf{CBL}_{d,t-2} : \text{the estimated CBL at the time of } t-2, \text{ and on the day of } (d). \end{array} \right.$$

^[12] In the PJM's comprehensive analysis of the CBL estimation methods (KEMA, 2011; PJM Interconnection (PJM), 2011), this adjustment is called a 'multiplicative' adjustment.

^[13] The interval or range of the loads and CBL for the computation of PAC and SAA is quite important for the accuracy of the CBL estimation, and it is also related to the gaming of the CBL. If it is too long, it cannot reflect well the recent changes in the loads. On the other hand, if it is too short, there would be a risk of CBL manipulation, because, for a short period, the costs for CBL manipulation will be small. Therefore, it is important to find out the proper interval or range of it to reflect the recent changes well, and at the same time, it could cause preventive costs for CBL manipulation. In South Korea, for the calculation of the SAA, KPX uses three-time slots (3 hours, $t - 1$, $t - 2$, and $t - 3$) before the DR event time (KPX, 2019, Appendix 28, pp. 528–530).

Second, the following is the additively adjusted CBL:

$$\text{Updated CBL}_{d,t}^{\text{SAA}} = \text{CBL}_{d,t}^{\text{WMA}} + \text{SAA} \quad (3.15)$$

For the SAA option, we use the following adjustment coefficient and add it to the preliminarily estimated CBL at the time of t .

$$\text{SAA} = \max \left\{ \frac{(\ell_{d,t-1} - \text{CBL}_{d,t-1}) + (\ell_{d,t-2} - \text{CBL}_{d,t-2})}{2}, 0 \right\} \quad (3.16)$$

$$\begin{aligned} \text{CBL}^{\text{WMA}} + \text{SAA} &= \text{SAA} + \text{CBL}^{\text{WMA}} \\ &= \text{SAA} + \left(\text{CBL}_1^{\text{WMA}} \quad \text{CBL}_2^{\text{WMA}} \quad \dots \quad \text{CBL}_{24}^{\text{WMA}} \right) \end{aligned} \quad (3.17)$$

where,

$$\left\{ \begin{array}{ll} \text{CBL}^{\text{WMA}} + \text{SAA} & : \text{ a vector of CBL with Symmetric Additive Adjustment,} \\ \text{SAA} & : \text{ additive adjustment coefficient for the SAA option,} \\ \ell_{d,t-1} & : \text{ the load (demand) at the time of } t-1, \text{ and on the day of } (d), \\ \ell_{d,t-2} & : \text{ the load (demand) at the time of } t-2, \text{ and on the day of } (d), \\ \text{CBL}_{d,t-1} & : \text{ the estimated CBL at the time of } t-1, \text{ and on the day of } (d), \\ \text{CBL}_{d,t-2} & : \text{ the estimated CBL at the time of } t-2, \text{ and on the day of } (d). \end{array} \right.$$

The following Figure 3.5 demonstrates the loads of the six similar non-event days which were used for the estimation and the four estimated CBLs based on different CBL estimation methods—simple average (CBL^{avg}), weighted moving average (CBL^{WMA}), weighted moving average + proportional adjustment ($\text{CBL}^{\text{WMA}} \cdot \text{PAC}$), and weighted moving average + symmetric additive adjustment ($\text{CBL}^{\text{WMA}} + \text{SAA}$). Table 3.2 summarizes the actual loads and four estimated CBLs for the DR event times, $t = 17h$ and $t = 18h$.

As can be seen in Figure 3.5, the loads were in the increasing trend from the earliest day (2016/07/29) to the DR event day (2016/08/12 in red), which was the peak period. The estimated CBLs of CBL^{avg} and CBL^{WMA} are about in the middle of the six similar non-event days, and the latter is slightly better than the former but not a big difference.

We can also visually notice that the two estimated CBLs of $\text{CBL}^{\text{WMA}} \cdot \text{PAC}$ and $\text{CBL}^{\text{WMA}} + \text{SAA}$ are very close to the actual loads and there is a very subtle difference between the two CBLs. Considering both of the figure and the table below, therefore, we can conclude that the two CBLs of $\text{CBL}^{\text{WMA}} \cdot \text{PAC}$ and $\text{CBL}^{\text{WMA}} + \text{SAA}$ perform much better than the two CBLs of CBL^{avg} and CBL^{WMA} , and between the two CBLs of $\text{CBL}^{\text{WMA}} \cdot \text{PAC}$ and $\text{CBL}^{\text{WMA}} + \text{SAA}$ the estimated CBL of $\text{CBL}^{\text{WMA}} + \text{SAA}$ is slightly better than another.

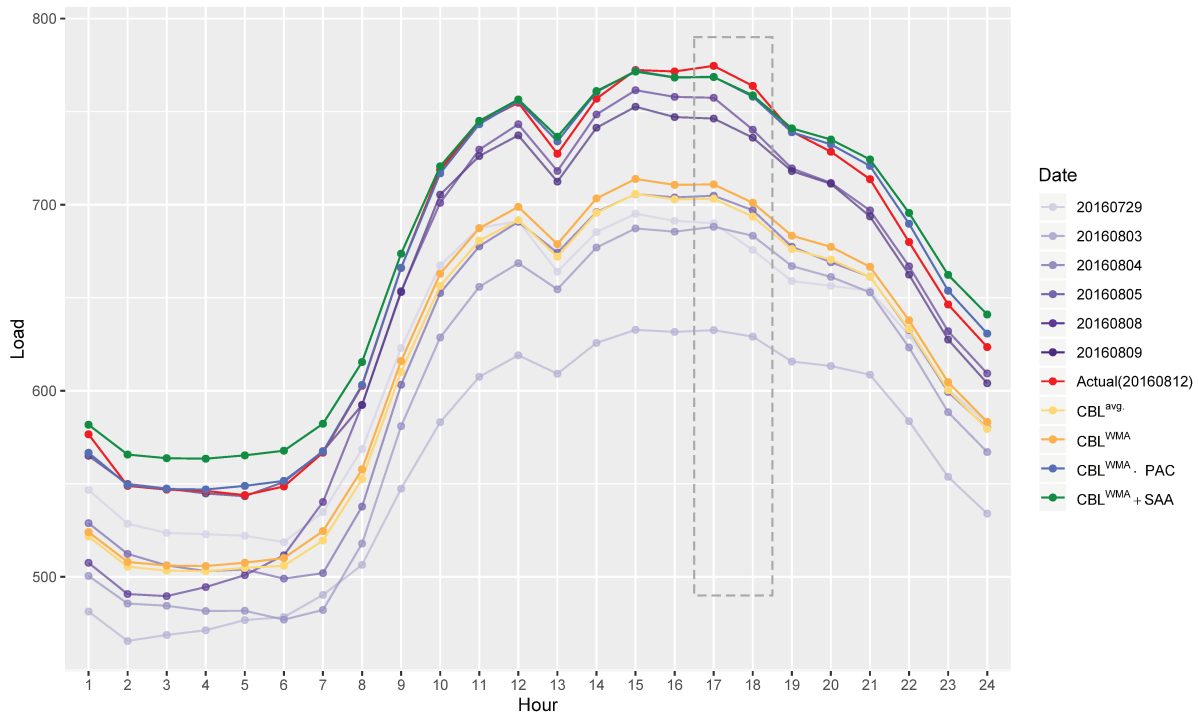


Figure 3.5: The Visual Comparison among the CBLs Established with Different Methods (W)

Source: The original load data before rescaling, “대국민 전력수급현황 공유 시스템” (Public Information Sharing System on Electricity Demand and Supply), KPX, [On-line], Available: <https://openapi.kpx.or.kr/sukub.do#>

Table 3.2: Summary of the Established CBLs for the Event Times (W)

	2016-08-12			
	...	17h	18h	...
Actual Load	...	774.60	763.83	...
CBL^{avg}	...	703.21	693.58	...
CBL^{WMA}	...	710.89	701.05	...
$CBL^{WMA} \cdot PAC$...	770.52	759.86	...
$CBL^{WMA} + SAA$...	770.63	760.80	...

On top of the visual observation, in order to numerically assess the four established CBL with different methods (simple average, weighted moving average, weighted moving average + proportional adjustment, and weighted moving average + symmetric additive adjustment), we are going to measure MAPE and RRMSE for the four different CBLs, and then compare them.

The following Figure 3.6 shows the results of the accuracy assessment for the four estimated CBLs in terms of MAPE and RRMSE, and Table 3.3 summarizes the results. The results are the same both in terms of MAPE and RRMSE. The estimated CBL of $CBL^{WMA} + SAA$ shows the least error both in the upper panel and the lower panel in the figure—those are less than 0.5%. With this comparison of MAPE and RRMSE of the four different CBL methods, we can conclude that $CBL^{WMA} + SAA$ (symmetric additive adjustment) is the best, although there is no big difference between the two methods $CBL^{WMA} \cdot PAC$ and $CBL^{WMA} + SAA$, proportional adjustment and additive adjustment.

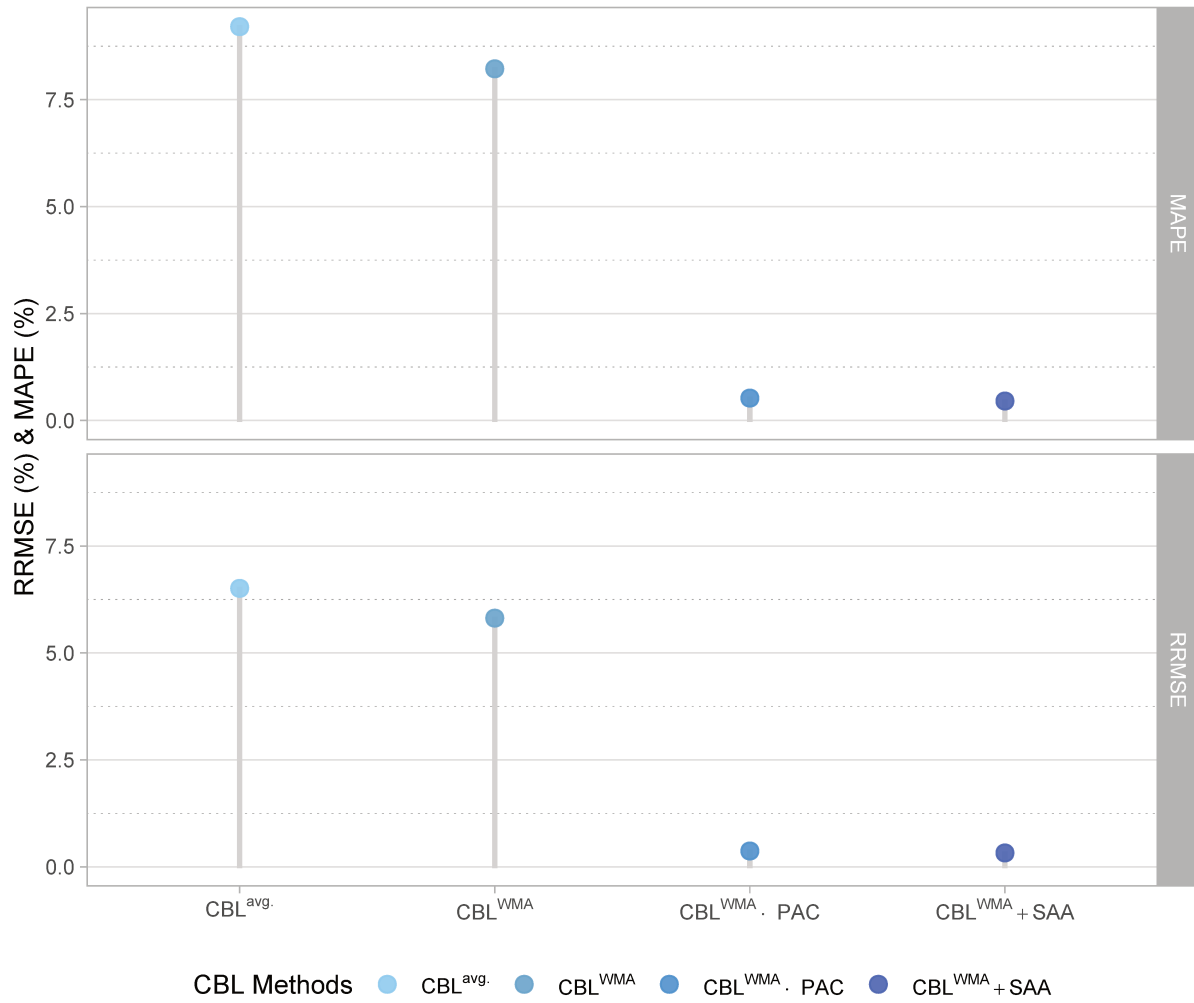


Figure 3.6: The CBL Accuracy Comparison (MAPE & RRMSE) among the CBLs Established with Different Methods

Table 3.3: The CBL Accuracy Comparison (MAPE and RRMSE) among the CBLs Established with Different Methods

	$CBL^{avg.}$	CBL^{WMA}	$CBL^{WMA} \cdot PAC$	$CBL^{WMA} + SAA$
MAPE	9.21%	8.22%	0.52%	0.45%
RRMSE	6.51%	5.81%	0.37%	0.32%

3.5 CBL for an Average Household in France

According to [Smart Energy Demand Coalition \(2017, p. 10\)](#), it seems that at least up to 2017, there was no consensus as to the methodologies for CBL estimation in France, especially for NEBEF. Actually, from NEBEF 1.0 to NEBEF 3.1 ([RTE, 2018a](#)), there has been a number of experiments and tests in order to find the best methodologies for CBL estimation. In the most recent regulation of NEBEF, that is NEBEF 3.1, now there are several methodologies to establish CBLs for the participants, such as ‘Méthode du rectangle à double référence corrigée’, ‘Méthode du rectangle algébrique site à site’, ‘Méthode par prévision de consommation’, and ‘Méthode par historique de consommation’. Considering the importance of the accurate CBL methodology and the fact that if we could provide several possible methodologies to the DR participants so that the participants can find the most suitable CBL methodologies for them, then it can increase their motivation to participate in it ([Smart Energy Demand Coalition, 2017, p. 81](#)), it will be meaningful to test several CBL methodologies and to suggest better CBL methodologies for the NEBEF mechanism in France. Therefore, here I can find the contribution of this section of the research by comparing different CBL calculation methodologies between South Korea and France.

In order to establish and assess a demonstrative CBL for France’s NEBEF mechanism, I am going to focus on 7 p.m. (19:00, the two-time slots for $t = 37$ and $t = 38$ for 30 minute interval a day, that is half-hourly data) on Monday, January 18, 2016, which was the peak demand in 2016 for France (Fig. 2.4). In the framework of the NEBEF mechanism, there are two types of the electricity consumption clients: 1. a Profiled Client (‘un Site de Soutirage Profilé’); 2. a Client with the AMI (‘un Site de Soutirage Télérelevé’). It was planned to deploy the AMI (Smart Metering) by 2020—three million smart meters between 2014 and 2016, and then 32 million smart meters from 2017 to 2020. Because explicit Demand Response is largely based on the AMI, I am going to concern only with the residential clients equipped with the AMI (‘un Site de Soutirage Télérelevé’) in this section.

In NEBEF mechanism, the load duration curve (‘Courbe de Consommation’) for a residential client with the AMI is constructed for every 10 minutes (‘Pas 10 minutes’) and the CBL (‘Courbe de Référence’) is established for every 30 minutes (‘Pas Demi-Horaire’)—this is the difference between France’s NEBEF mechanism and South Korea’s Demand-side Resource Trading Market because at South Korea’s Demand-side Resource Trading Market both of the load duration curve and CBL are established with one hour interval. However, with the difficulties to obtain an actual load dataset for every 10 minutes which was tele-measured by the AMI, I am going to rescale the aggregate national load duration curve measured for every 30 minutes (half-hourly data) to build a load duration curve and CBL for an average French household.

In 2016, the residential sector accounts for 36% of France’s total electricity consumption ([RTE, 2017](#)).^[14] As of March 31, 2016, the total number of the electricity consumption clients in the residential sector, that is households, is 31,889,000 ([Commission de Régulation de l’Energie \(CRE\), 2016, p. 6](#)).^[15]

The following Figures 3.7, 3.8, 3.9 and Table 3.4 show the number, the total consumption, the average consumption of residential customers by Département in 2016, France and the top 10 Départements.^[16] Examining these figures and summary table, we can identify the possible target area or group in order to exploit the maximum level of the DR mechanism.

^[14] Business sector 27%, heavy industry 17%, and SMEs/SMI 10%. For the percentage of residential sector in 2000, 2005, 2010, 2014, 2015, it is 33.4%, 32.8%, 36.4%, 35.2%, 35.9%, respectively. It can be calculated referring to the following document: [IEA, 2017, Electricity Information 2017](#). IEA, Paris. p. III.197, Table 3a. Summary electricity production and consumption₁ (TWh).

^[15] As of December 31, 2015, it was 31,790,000, as of December 31, 2017, it was 32,396,000, and as of March 31, 2018, it was 32,508,000 ([Commission de Régulation de l’Energie \(CRE\), 2018](#)).

^[16] Please, refer to other figures for the number of customers (Fig. A.25), total consumption (Fig. A.26), and average consumption (Fig. A.27) in the industrial sector by Département, 2016 in France in [Appendix A: Supplementary Figures & Tables](#) of this dissertation.

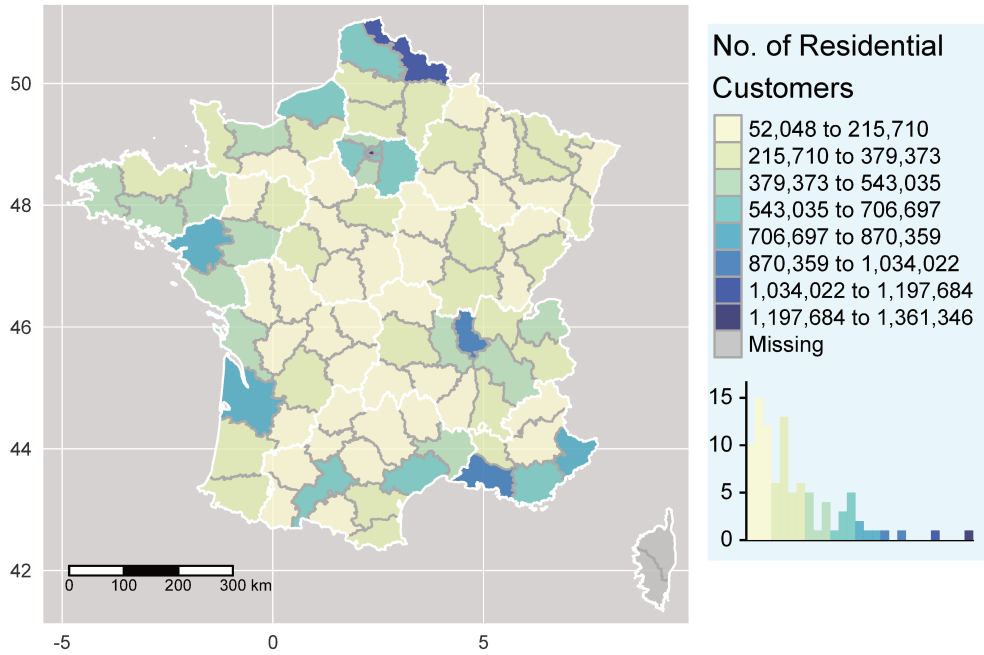


Figure 3.7: The Number of Residential Customers by Département, 2016 in France

Source: “Consommation électrique annuelle à la maille département”, 2018, by Enedis, [Online], Available: <https://goo.gl/kqVMi2>

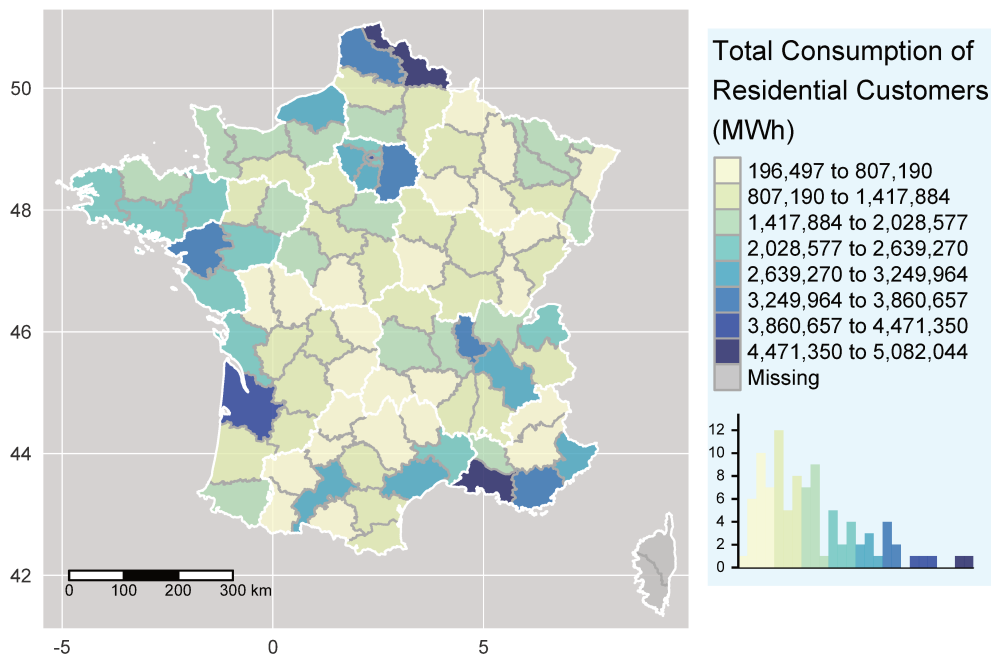


Figure 3.8: The Total Consumption of Residential Customers by Département, 2016 in France (MWh)

Source: “Consommation électrique annuelle à la maille département”, 2018, by Enedis, [Online], Available: <https://goo.gl/kqVMi2>

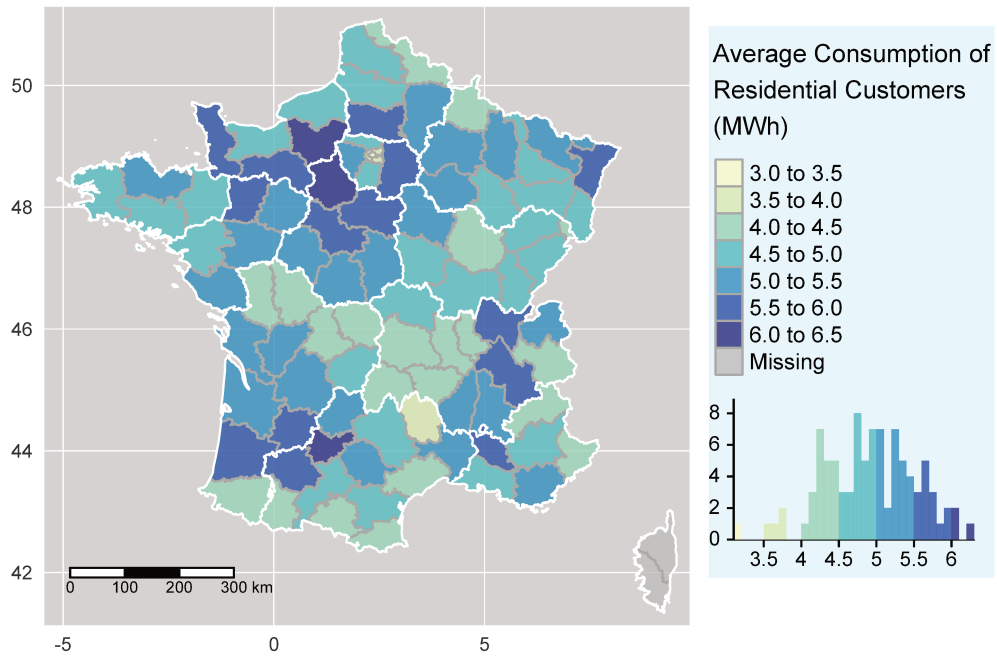


Figure 3.9: The Average Consumption of Residential Customers by Département, 2016 in France (MWh)

Source: “Consommation électrique annuelle à la maille département”, 2018, by Enedis, [Online], Available: <https://goo.gl/kqVMi2>

Table 3.4: The Top 10 Département in terms of Number, Total Consumption, and Average Consumption in Residential Sector

Rank	Dépt.	No. Sites	Dépt.	Total Conso. (MWh)	Dépt.	Avg. Conso. (MWh)
1	Paris	1,361,346	Nord	5,082,044	Eure	6.20
2	Nord	1,155,209	Bouches-du-Rhone	4,963,039	Tarn-et-Garonne	6.09
3	Bouches-du-Rhone	997,053	Paris	4,292,061	Eure-et-Loir	6.02
4	Rhone	889,003	Gironde	4,135,094	Ain	5.99
5	Gironde	818,101	Rhone	3,837,773	Vaucluse	5.98
6	Hauts-de-Seine	786,972	Var	3,590,573	Loir-et-Cher	5.80
7	Alpes-Maritimes	747,245	Loire-Atlantique	3,434,868	Gers	5.78
8	Loire-Atlantique	716,446	Seine-et-Marne	3,382,133	Mayenne	5.77
9	Var	683,842	Pas-de-Calais	3,262,666	Seine-et-Marne	5.75
10	Haute-Garonne	681,809	Haute-Garonne	3,243,072	Manche	5.69

Source: "Consommation électrique annuelle à la maille département", 2018, by Enedis, [On-line], Available: <https://goo.gl/kqVMi2>

According to the above-mentioned information on the residential sector in France, we can obtain the following rescaled load profile of an average household (W) from the national aggregate load (MW).

$$\mathbf{L}_{366 \times 144}^{\text{agg.}} = \begin{matrix} & \begin{matrix} 1 & 2 & \dots & 144 \end{matrix} \\ \begin{matrix} 1 \\ 2 \\ \vdots \\ 366 \end{matrix} & \begin{pmatrix} \ell_{1,1} & \ell_{1,2} & \dots & \ell_{1,144} \\ \ell_{2,1} & \ell_{2,2} & \dots & \ell_{2,144} \\ \vdots & \vdots & \ddots & \vdots \\ \ell_{366,1} & \ell_{366,2} & \dots & \ell_{366,144} \end{pmatrix} \end{matrix} \approx \mathbf{L}_{366 \times 48}^{\text{agg.}} = \begin{matrix} & \begin{matrix} 1 & 2 & \dots & 48 \end{matrix} \\ \begin{matrix} 1 \\ 2 \\ \vdots \\ 366 \end{matrix} & \begin{pmatrix} \ell_{1,1} & \ell_{1,2} & \dots & \ell_{1,48} \\ \ell_{2,1} & \ell_{2,2} & \dots & \ell_{2,48} \\ \vdots & \vdots & \ddots & \vdots \\ \ell_{366,1} & \ell_{366,2} & \dots & \ell_{366,48} \end{pmatrix} \end{matrix} \quad (3.18)$$

$$\mathbf{L}_{366 \times 48}^{\text{avg.res.}} = \frac{36}{100} \times \frac{1}{31,889,000} \times 1,000 \times 1,000 \times \mathbf{L}_{366 \times 48}^{\text{agg.}} \quad (3.19)$$

where,

{	$L_{366 \times 144}^{agg.}$: a matrix of aggregate loads of France measured for every 10 minutes, 366 rows \times 144 (= 24 \times 10) columns, in 2016 (there were 366 days in 2016),
	$L_{366 \times 48}^{agg.}$: a matrix of aggregate loads of France measured for every 30 minutes, 366 rows \times 48 (= 24 \times 2) columns,
	$L_{366 \times 48}^{avg.res.}$: a matrix of rescaled loads of an average household of France in (W), 366 rows \times 48 (= 24 \times 2) columns,
	$l_{d,t}$: actual load at the time slot t and on the day of d , $d \in D = \{1, 2, \dots, 366\}$, $t \in T = \{1, 2, \dots, 144\}$ for a load measured by 10 minute interval, $t \in T = \{1, 2, \dots, 48\}$ for a load measured by 30 minute interval.

In the NEBEF mechanism (in NBEF 3.1), there are mainly four methods for establishing a CBL:^[17]

1. Méthode du rectangle à double référence corrigée,
2. Méthode du rectangle algébrique site à site,
3. Méthode par prévision de consommation,
4. Méthode par historique de consommation.

The first method of ‘Méthode du rectangle à double référence corrigée’ is the default method of NEBEF both for ‘un Site de Soutirage Profilé’ and ‘un Site de Soutirage Télérelevé’. Also, it is one of the family of ‘les méthodes du rectangle’ which includes ‘méthode du rectangle simple’, ‘méthode du rectangle à double référence’, and ‘méthode du rectangle à double référence corrigée’.^[18] This family of the method uses the loads before and after the DR events. Even though this first method is default both for ‘un Site de Soutirage Profilé’ and ‘un Site de Soutirage Télérelevé’ it seems like more suitable for ‘un Site de Soutirage Profilé’ because there is no available previous historical data for ‘un Site de Soutirage Profilé’ so it cannot help relying only on the load record of the DR event day. If an LA (‘l’Opérateur d’Effacement’) wants to apply other methods to establishing a CBL, then it can declare the method when it creates a Load Shedding Entity (Entité d’Effacement (EDE)).^[19]

The second method of ‘Méthode du rectangle algébrique site à site’ is only applicable to the Profiled Load Shedding Entities (‘Entités d’Effacement Profilées’) consisting of more than three thousand (3,000) of ‘Sites de Soutirage Profilés’. This method is just the algebraic sum of the applications of the first method of ‘Méthode du rectangle à double référence corrigée’ to each of its consisting clients.

The third method of ‘Méthode par prévision de consommation’ is applicable only to the Tele-measured Load Shedding Entities (Entités d’Effacement Télérelevées). If an LA wants to utilize this method, it needs to declare this method when it creates the Load Shedding Entity, and then it transfers the data to RTE.

The last method of ‘Méthode par historique de consommation’ is also applicable only to the Tele-measured Load Shedding Entity. This method is equivalent to the ‘conventional day match (or matching) method’ that

^[17] It seems that at the experimental phase, the panel data analysis was also tested for a possible CBL estimation method. For this, please refer to the following: RTE, 2013, *Expérimentation sur la valorisation des effacements de consommation sur les marchés de l’énergie (dispositif NEBEF 1)*, pp. 60–61. [On-line], Available: https://www.rte-france.com/sites/default/files/2013_10_16_nebef_rapport_de_consultation_vdiff.pdf

^[18] In order to better understand the family of ‘les méthodes du rectangle’, please refer to the following document: RTE, 2013, *Expérimentation sur la valorisation des effacements de consommation sur les marchés de l’énergie (dispositif NEBEF 1)*, pp. 55–57. [On-line], Available: https://www.rte-france.com/sites/default/files/2013_10_16_nebef_rapport_de_consultation_vdiff.pdf

^[19] One Load Shedding Entity (Entité d’Effacement) consists of more than one site of an electricity customer (‘des Sites de Soutirage Profilé’ or ‘des Sites de Soutirage Télérelevé’). Also, a Perimeter of Load Shedding consists of more than one Load Shedding Entity. On the top level, an LA may have several Perimeters of Load Shedding. Therefore, we can see the following levels: Sites de Soutirage \Rightarrow Entités d’Effacement \Rightarrow Périmètre d’Effacement \Rightarrow l’Opérateur d’Effacement

is mentioned in the section 3.2. As we have seen, in this category of the conventional day match method there are a number of variants of this method and some of them are used in the U.S. and South Korea. In the NEBEF mechanism there are four variants of this day math method:

‘Méthode par historique de consommation’ :

1. Moyenne 10 jours,
2. Médiane 10 jours,
3. Moyenne 4 semaines,
4. Médiane 4 semaines.

Since ‘median’ can be thought of as the fully trimmed mid-range, we can consider the methods of ‘Médiane 10 jours’ and ‘Médiane 4 semaines’ as ‘Average 2/10 (=Mid 2/10)’ and ‘Average 2/4 (=Mid 2/4)’ respectively.

Because I am focusing on the residential sector and the households equipped with the AMI, I do not consider the first and second method of ‘Méthode du rectangle à double référence corrigée’ and ‘Méthode du rectangle algébrique site à site’ respectively. Moreover, in the regulation for the NEBEF mechanism, there are no specific formulas for the third method of ‘Méthode par prévision de consommation’ and it seems that it is up to LAs to choose any formulas to calculate the load estimations with this method. Therefore, I am going to consider and utilize the last method of ‘Méthode par historique de consommation’ with its four variants in the following.

For the first variant of the method: ‘Moyenne 10 jours’,

$$\text{CBL}_{d,t}^{\text{avg.10}} = \frac{1}{10} \sum_{i=1}^{10} \ell_{d-i,t} \quad (3.20)$$

where,

$$\left\{ \begin{array}{l} \text{CBL}_{d,t}^{\text{avg.10}} : \text{ a customer baseline load for the DR event day, } d \text{ at the event time slot, } t, \\ \text{ using the method of 'Moyenne 10 jours'} \\ d \in D = \{1, 2, \dots, 366\} \\ t \in T = \{1, 2, \dots, 48\}, \\ \ell_{d-i,t} : \text{ actual load at the time slot of } t \text{ and on the day of } (d-i) \text{ (} i^{\text{th}} \text{ day before the DR} \\ \text{ event day),} \\ i \in I = \{1, 2, \dots, 10\}. \end{array} \right.$$

$$\begin{aligned} \text{CBL}^{\text{avg.10}} &= \frac{1}{10} \mathbf{1}_{10}^T \cdot \mathbf{S}^{10} \\ &= \frac{1}{10} \begin{pmatrix} 1 & \dots & 1 \end{pmatrix} \cdot \begin{pmatrix} \ell_{d-10,1} & \ell_{d-10,2} & \dots & \ell_{d-10,48} \\ \ell_{d-9,1} & \ell_{d-9,2} & \dots & \ell_{d-9,48} \\ \vdots & \vdots & \ddots & \vdots \\ \ell_{d-1,1} & \ell_{d-1,2} & \dots & \ell_{d-1,48} \end{pmatrix} \\ &= \begin{pmatrix} \text{CBL}_1^{\text{avg.10}} & \text{CBL}_2^{\text{avg.10}} & \dots & \text{CBL}_{48}^{\text{avg.10}} \end{pmatrix} \end{aligned} \quad (3.21)$$

where,

$$\left\{ \begin{array}{l} \mathbf{CBL}^{\text{avg-10}} : \text{a vector of CBL which is calculated with the method of 'Moyenne 10 jours',} \\ \mathbf{1}_{10}^T : \text{a transposed vector of ten elements of 1 (one), that is a sum vector,} \\ \mathbf{S}^{10} : \text{a matrix of the similar non-event 10 days consisting of the loads of the pre-} \\ \quad \text{vious ten days,} \\ l_{d-i,t} : \text{actual load at the time slot of } t \text{ and on the day of } (d-i) \text{ (} i^{\text{th}} \text{ day before the DR} \\ \quad \text{event day),} \\ i \in I = \{1, 2, \dots, 10\}. \end{array} \right.$$

For the second variant of the method: 'Médiane 10 jours',

$$\begin{aligned} \mathbf{CBL}^{\text{med.10}} &= \text{Median}(\mathbf{S}^{10}) \\ &= \text{Median} \left(\begin{pmatrix} \ell_{d-10,1} & \ell_{d-10,2} & \dots & \ell_{d-10,48} \\ \ell_{d-9,1} & \ell_{d-9,2} & \dots & \ell_{d-9,48} \\ \vdots & \vdots & \ddots & \vdots \\ \ell_{d-1,1} & \ell_{d-1,2} & \dots & \ell_{d-1,48} \end{pmatrix} \right) \\ &= \left(\text{Median}(\mathbf{s}_1^{10}) \quad \text{Median}(\mathbf{s}_2^{10}) \quad \dots \quad \text{Median}(\mathbf{s}_{48}^{10}) \right) \\ &= \left(\mathbf{CBL}_1^{\text{med.10}} \quad \mathbf{CBL}_2^{\text{med.10}} \quad \dots \quad \mathbf{CBL}_{48}^{\text{med.10}} \right) \end{aligned} \quad (3.22)$$

where,

$$\left\{ \begin{array}{l} \mathbf{CBL}^{\text{med.10}} : \text{a vector of CBL which is calculated with the method of 'Médiane 10 jours',} \\ \mathbf{S}^{10} : \text{a matrix of the similar non-event days consisting of the loads of the previous} \\ \quad \text{ten days,} \\ l_{d-i,t} : \text{actual load at the time slot of } t \text{ and on the day of } (d-i) \text{ (} i^{\text{th}} \text{ day before the DR} \\ \quad \text{event day),} \\ i \in I = \{1, 2, \dots, 10\}, \\ \mathbf{s}_t^{10} : \text{the } t^{\text{th}} \text{ column vector of the matrix } \mathbf{S}^{10}, \text{ and it is the loads of the previous} \\ \quad \text{ten days for each time slot } t, \\ t \in T = \{1, 2, \dots, 48\}. \end{array} \right.$$

The following Figure 3.10 demonstrates the actual loads for every 30 minutes on Jan. 18, 2016, the loads of the ten previous days^[20] for the same time slots, and the two CBLs based on the method of 'Moyenne 10 jours' and 'Médiane 10 jours'. First of all, we can see that the actual loads were the highest loads—of course, because I chose the day of the peak demand, and we can see the increasing trend from the earliest day (2016-01-04) to the most recent day (2016-01-15), and finally the DR event day's (2016-01-18) actual loads.

Also, we can verify that the two CBLs based on the method of 'Moyenne 10 jours' and 'Médiane 10 jours' do not perform very well. It is worse than just the most recent day's loads themselves without any formula and calculation. Even though the CBL based on the method of 'Moyenne 10 jours' works slightly better than the CBL based on the method of 'Médiane 10 jours', there is no big difference between them.

^[20] When it comes to the ten previous days before Jan. 18, 2016, I only included the working days and excluded the holidays and weekends. In this case, there was no holiday among the original ten previous days, therefore, I simply used Jan. 4, 5, 6, 7, 8, 11, 12, 13, 14, and 15, 2016.

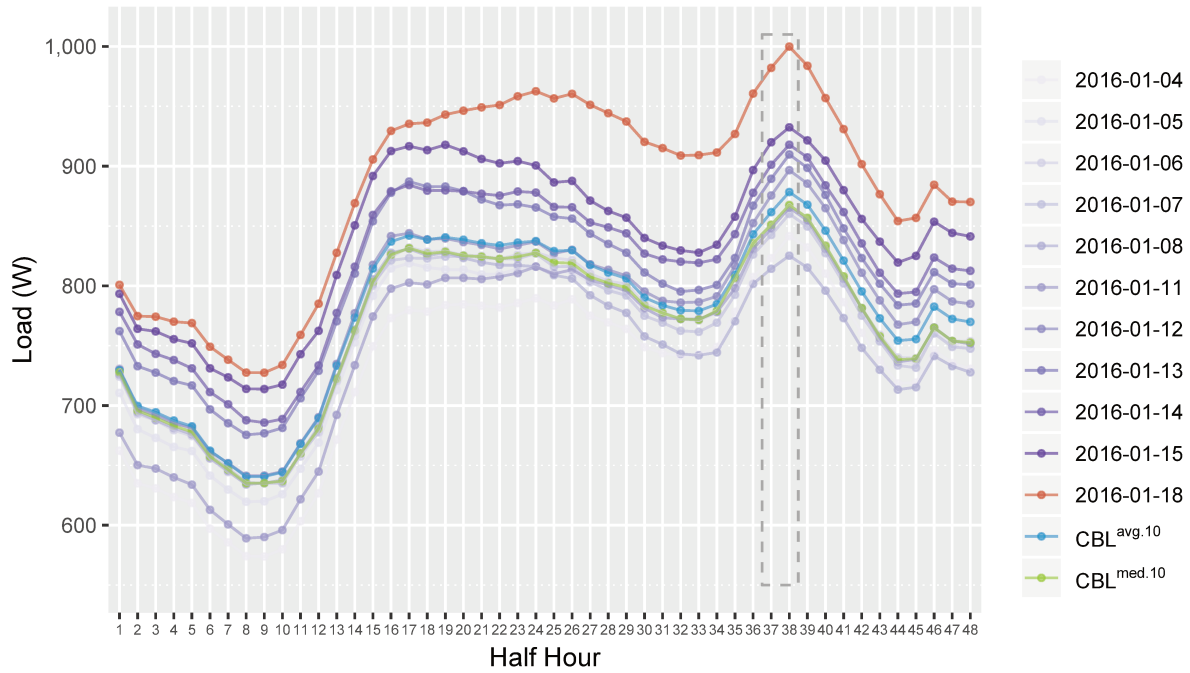


Figure 3.10: The Visual Comparison among the Loads of the Previous Ten Days, Actual Loads, CBLs based on the Ten Day Average and Median Method (W)

Source: The original load data before rescaling, RTE's PORTAIL CLIENTS, "Historique des consommations journalières en puissance". [On-line], Available: https://clients.rte-france.com/lang/fr/clients_traders_fournisseurs/vie/vie_stats_conso_inst.jsp

For the third variant of the method: 'Moyenne 4 semaines',

$$\text{CBL}_{d,t}^{\text{avg.4}} = \frac{1}{4} \sum_{i=1}^4 \ell_{d-i,t} \quad (3.23)$$

where,

$$\left\{ \begin{array}{l} \text{CBL}_{d,t}^{\text{avg.4}} : \text{customer baseline load for the DR event day, } d \text{ at the event time, } t, \text{ using the} \\ \text{method of 'Moyenne 4 semaines'} \\ d \in D = \{1, 2, \dots, 366\} \\ t \in T = \{1, 2, \dots, 48\}, \\ \ell_{d-i,t} : \text{actual load at the time slot of } t \text{ and on the day of } (d-i) \text{ (} i^{\text{th}} \text{ day before the DR} \\ \text{event day),} \\ i \in I = \{7, 14, 21, 28\}. \end{array} \right.$$

$$\begin{aligned}
\mathbf{CBL}^{\text{avg.4}} &= \frac{1}{4} \mathbf{1}_4^T \cdot \mathbf{S}^4 \\
&= \frac{1}{4} \begin{pmatrix} 1 & \dots & 1 \end{pmatrix} \cdot \begin{pmatrix} \ell_{d-28,1} & \ell_{d-28,2} & \dots & \ell_{d-28,48} \\ \ell_{d-21,1} & \ell_{d-21,2} & \dots & \ell_{d-21,48} \\ \ell_{d-14,1} & \ell_{d-14,2} & \dots & \ell_{d-14,48} \\ \ell_{d-7,1} & \ell_{d-7,2} & \dots & \ell_{d-7,48} \end{pmatrix} \\
&= \left(\mathbf{CBL}_1^{\text{avg.4}} \quad \mathbf{CBL}_2^{\text{avg.4}} \quad \dots \quad \mathbf{CBL}_{48}^{\text{avg.4}} \right)
\end{aligned} \tag{3.24}$$

where,

$$\left\{ \begin{array}{l}
\mathbf{CBL}^{\text{avg.4}} : \text{ a vector of CBL which is calculated with the method of 'Moyenne 4 semaines',} \\
\mathbf{1}_4^T : \text{ a transposed vector of four elements of 1 (one), that is a sum vector,} \\
\mathbf{S}^4 : \text{ a matrix of the similar non-event 4 days consisting of the loads of the previous four weeks on the same day (ex. Mon., \dots, Fri.),} \\
\ell_{d-i,t} : \text{ actual load at the time slot of } t \text{ and on the day of } (d-i) \text{ (} i^{\text{th}} \text{ day before the DR event day),} \\
i \in I = \{7, 14, 21, 28\}.
\end{array} \right.$$

For the last variant of the method: 'Médiane 4 semaines',

$$\begin{aligned}
\mathbf{CBL}^{\text{med.4}} &= \text{Median}(\mathbf{S}^4) \\
&= \text{Median} \left(\begin{pmatrix} \ell_{d-28,1} & \ell_{d-28,2} & \dots & \ell_{d-28,48} \\ \ell_{d-21,1} & \ell_{d-21,2} & \dots & \ell_{d-21,48} \\ \ell_{d-14,1} & \ell_{d-14,2} & \dots & \ell_{d-14,48} \\ \ell_{d-7,1} & \ell_{d-7,2} & \dots & \ell_{d-7,48} \end{pmatrix} \right) \\
&= \left(\text{Median}(\mathbf{s}_1^4) \quad \text{Median}(\mathbf{s}_2^4) \quad \dots \quad \text{Median}(\mathbf{s}_{48}^4) \right) \\
&= \left(\mathbf{CBL}_1^{\text{med.4}} \quad \mathbf{CBL}_2^{\text{med.4}} \quad \dots \quad \mathbf{CBL}_{48}^{\text{med.4}} \right)
\end{aligned} \tag{3.25}$$

where,

$$\left\{ \begin{array}{l}
\mathbf{CBL}^{\text{med.4}} : \text{ a vector of CBL which is calculated with the method of 'Médiane 4 semaines',} \\
\mathbf{S}^4 : \text{ a matrix of the similar non-event 4 days consisting of the loads of the previous four weeks on the same day (ex. Mon., \dots, Fri.),} \\
\ell_{d-i,t} : \text{ actual load at the time slot of } t \text{ and on the day of } (d-i) \text{ (} i^{\text{th}} \text{ day before the DR event day),} \\
i \in I = \{7, 14, 21, 28\}, \\
\mathbf{s}_t^4 : \text{ the } t^{\text{th}} \text{ column vector of the matrix } \mathbf{S}^4, \text{ and it is the loads of the previous four weeks for each time slot } t, \\
t \in T = \{1, 2, \dots, 48\}.
\end{array} \right.$$

The following Figure 3.11 demonstrates the actual loads for every 30 minutes on Jan. 18, 2016, the loads of the previous four weeks^[21] on the same day, that is in this case Monday, and the two CBLs based on the method of

^[21] When it comes to the previous four weeks before Jan. 18, 2016, I only included the working days and excluded the holidays and weekends. In this case, there was no holiday among the original previous four weeks, therefore, I simply used Dec. 21, 28, 2015, Jan. 4, and 11, 2016.

'Moyenne 4 semaines' and 'Médiane 4 semaines'. This time, we can see again that the actual loads were the highest loads comparing the loads of the previous four weeks, which means that the increasing trend from the earliest day (2015-12-21) to the most recent day (2016-01-11), and finally the DR event day's (2016-01-18) actual loads.

Again, we can verify that the two CBLs based on the method of 'Moyenne 4 semaines' and 'Médiane 4 semaines' do not perform very well. It is worse than just the most recent day's loads themselves without any formula and calculation. There is almost no difference between them.

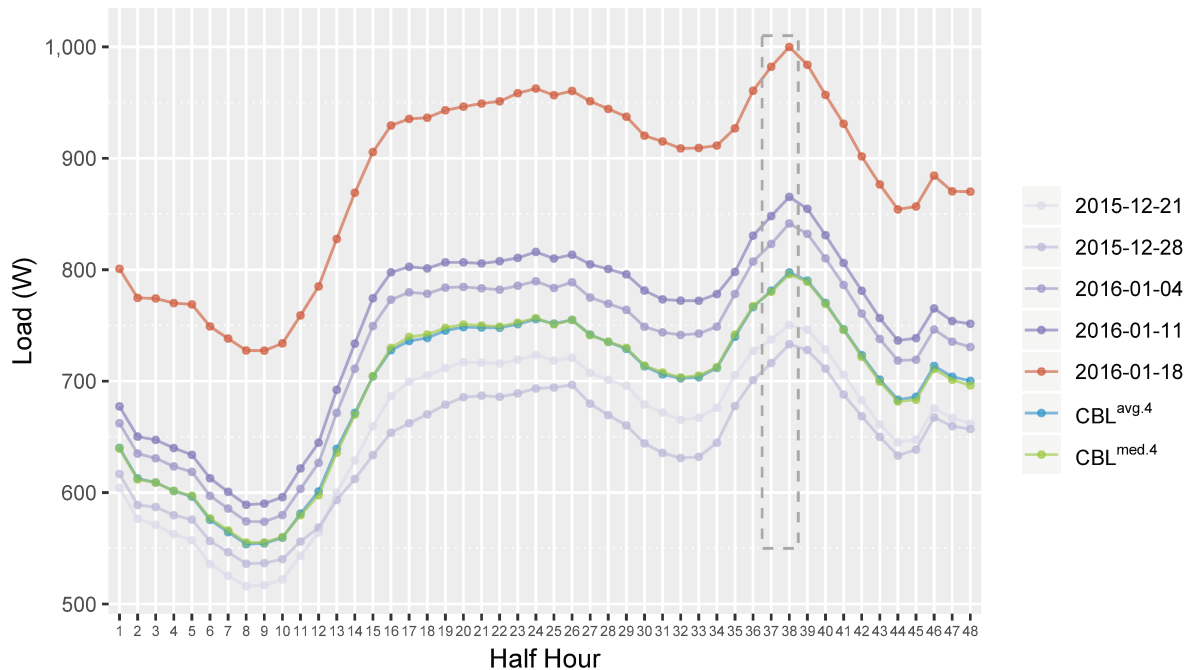


Figure 3.11: The Visual Comparison among the Loads of the Previous Four Weeks, Actual Load, CBLs based on the Four Week Average and Median Method (W)

Source: The original load data before rescaling, RTE's PORTAIL CLIENTS, "Historique des consommations journalières en puissance", [On-line], Available: https://clients.rte-france.com/lang/fr/clients_traders_fournisseurs/vie/vie_stats_conso_inst.jsp

The following Figure 3.12 shows the actual loads of the day of the peak demand and the four CBLs calculated based on the four methods of 'Moyenne 10 semaines', 'Médiane 10 semaines', 'Moyenne 4 semaines' and 'Médiane 4 semaines'. It is easy to notice that all the four methods do not perform well although the two methods of 'Moyenne 10 semaines', 'Médiane 10 semaines' outperform the other two methods of 'Moyenne 4 semaines', 'Médiane 4 semaines'. Even though the four CBLs are established for all the time slots of the 30-minute interval, the dotted gray rectangle highlights the two-time slots of $t = 37$ and $t = 38$, that is, 7 p.m. (19:00)—the time of the peak demand in 2016, France. With Table 3.5 we can verify the detailed numbers for the actual loads and four CBLs at the time slot $t = 37$ and $t = 38$.

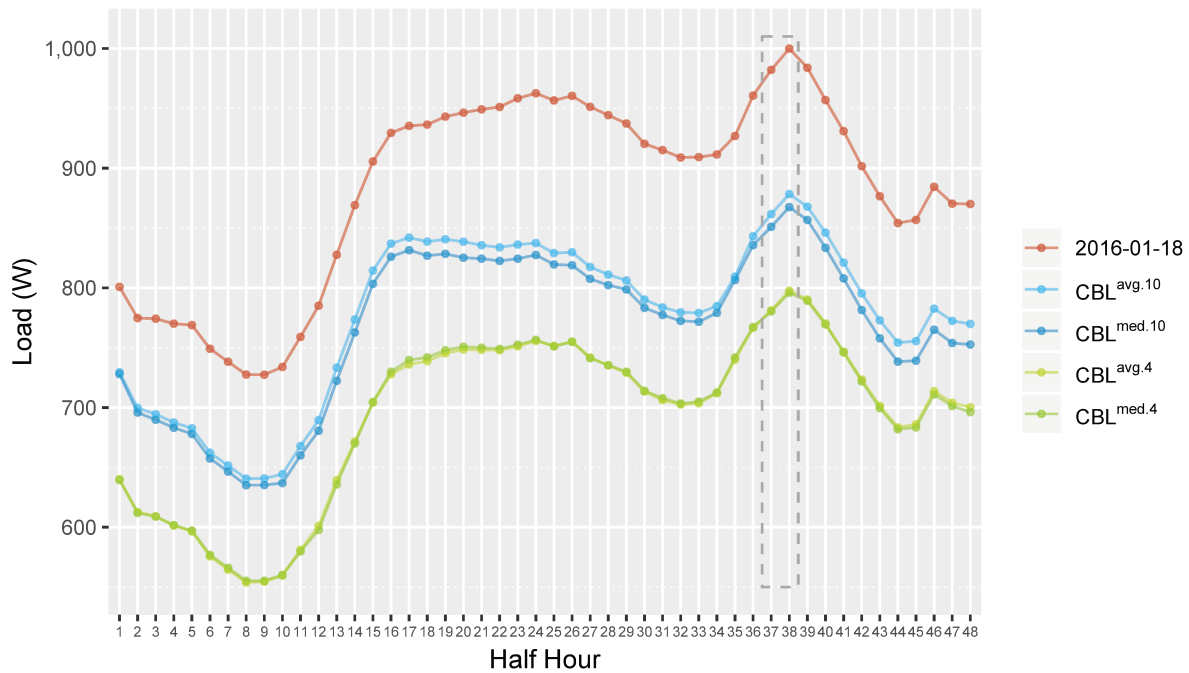


Figure 3.12: Comparing the Actual Loads with all the Four CBLs (W)

Table 3.5: Summary of the Established CBLs for the NEBEF (DR) Event Times (W)

	2016-01-18			
	...	$t = 37$	$t = 38$...
Actual Load	...	982.11	999.89	...
$CBL^{avg.10}$...	861.60	878.36	...
$CBL^{med.10}$...	850.99	867.45	...
$CBL^{avg.4}$...	781.22	797.58	...
$CBL^{med.4}$...	780.27	795.92	...

In addition to the visual comparison between the actual loads and the four CBLs, we can measure the performance (accuracy) of the CBLs by calculating the estimation error between the actual loads and the four CBLs. In the NEBEF mechanism, the following ‘absolute error’ is used in order to assess the quality of a CBL based on the method of ‘Méthod par historique de consommation’.^[22]

$$\begin{aligned} \text{Erreur absolue } (\epsilon) &= \frac{1}{N} \sum_{i=1}^N \frac{|\text{Référence historique de consommation}_i - \text{Consommation}_i|}{\text{Capacité d'Effacement Minimale du Site de Soutirage}} \\ \Rightarrow \text{Absolute Error } (\epsilon) &= \frac{1}{N} \sum_{i=1}^N \frac{|CBL_{d,t} - \text{Actual Electricity Load}_{d,t}|}{\text{Minimum Capacity of Demand Response}} \end{aligned} \quad (3.26)$$

In terms of ‘Capacité d’Effacement Minimale du Site de Soutirage’ (Minimum Capacity of Demand Response) in the above-mentioned formula 3.26, it is declared by the Load Aggregator at the initial stage. There is no

^[22] RTE, 2018a, p. 64, 7.2.5.1 Indicateur de qualité pour la méthode «par historique de consommation».

specific formula of this Minimum Capacity of Demand Response and it seems that it is up to the Load Aggregator. Therefore it is difficult to set the proper level of 'Minimum Capacity of Demand Response' at this stage. For the sake of convenience of the analysis, I will use 'Actual Electricity Load' instead of 'Minimum Capacity of Demand Response', then the above-mentioned formula of the 'Absolute Error' becomes the formula of 3.4 in the section 3.3. In addition to MAPE, I am also going to check out the formula of 3.5 in the same section 3.3 as I have applied them to the South Korean case's CBLs.

In the following Figure 3.13, we can compare the accuracies of all the four CBLs utilized in the NEBEF mechanism at the same time in terms of MAPE and RRMSE. As we have compared them visually in Figure 3.12 and numerically in Table 3.5, MAPE and RRMSE tell us the same result that the two methods using previous ten days outperform the two methods using previous four weeks, and that the best one is based on the average ten days method ($CBL^{avg.10}$). Table 3.6 summarizes the result of the accuracy assessment for the four CBLs in terms of MAPE and RRMSE.

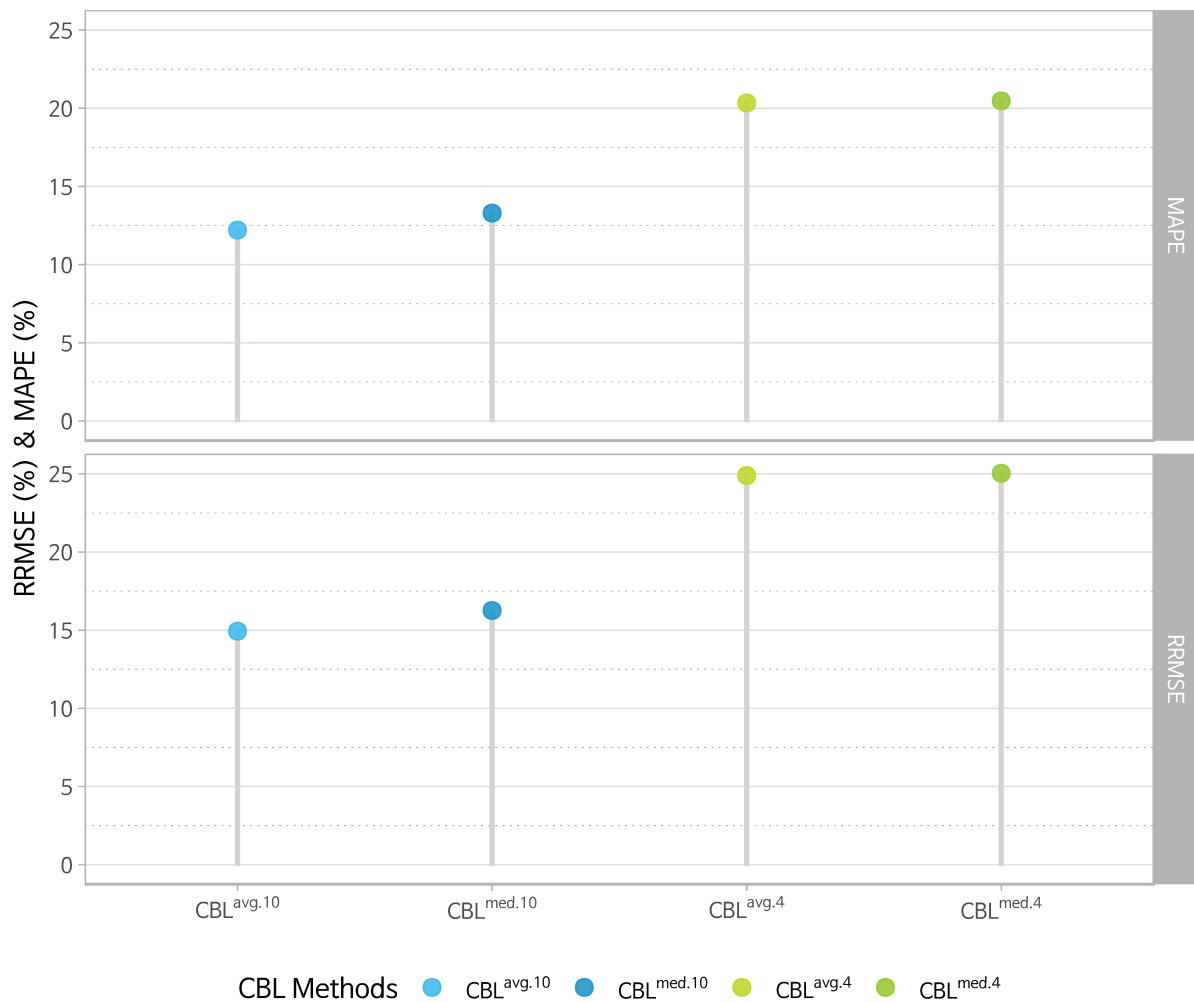


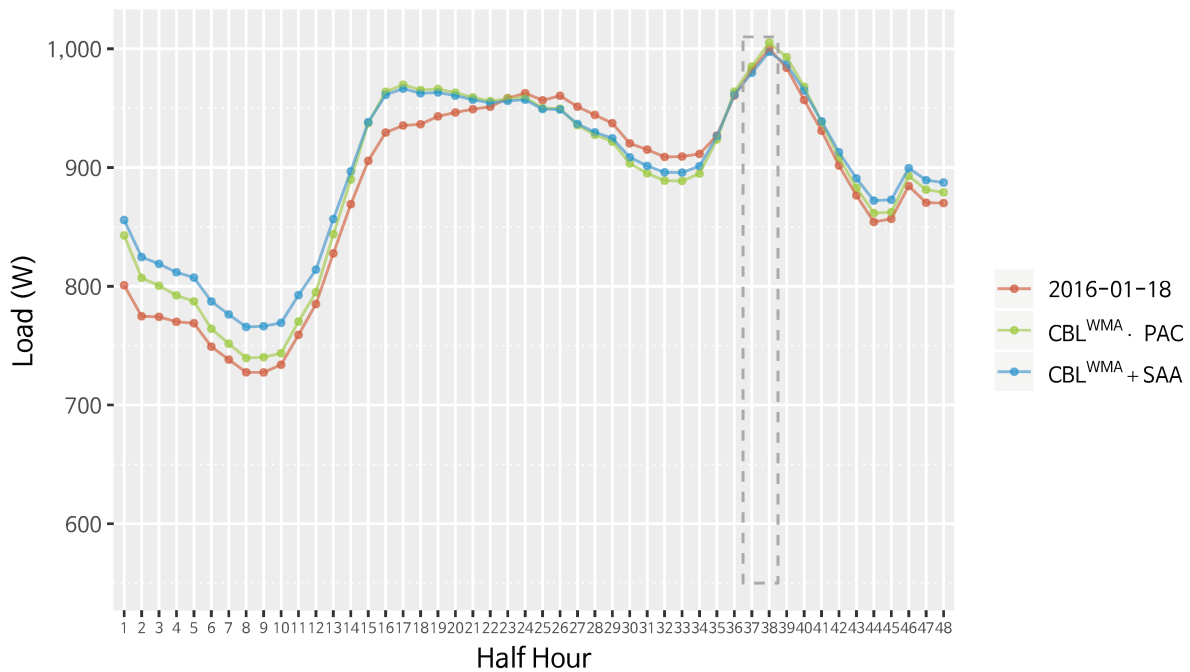
Figure 3.13: The CBL Accuracy Comparison (MAPE & RRMSE) among the CBLs Established with Different Methods

Table 3.6: The CBL Accuracy Comparison (MAPE and RRMSE) among the CBLs Established with Different Methods

	CBL ^{avg.10}	CBL ^{med.10}	CBL ^{avg.4}	CBL ^{med.4}
MAPE	12.21%	13.30%	20.34%	20.48%
RRMSE	14.94%	16.26%	24.89%	25.03%

In the section 3.4 we could find out that the two CBL methods based on Weighted Moving Average (WMA) with Proportional Adjustment Coefficient (PAC) and with Symmetric Additive Adjustment (SAA), those are $CBL^{WMA \cdot PAC}$ and $CBL^{WMA + SAA}$ respectively, demonstrated quite high and satisfactory performances for the baseline estimation. Considering the result, it would be worthwhile applying these CBL methods to the French NEBEF mechanism in order to find out a room to improve the CBL estimation methodology.

The following Figure 3.14 shows that the two CBL methods again perform very well for the French NEBEF case, too. For the two-time slots $t = 37$ and $t = 38$, there is almost no difference between them, $CBL^{WMA + SAA}$ is better very slightly, though. We can check out this subtle difference with the summary Table 3.7.

**Figure 3.14:** Comparing the Actual Loads with the Two CBL Methods of $CBL^{WMA \cdot PAC}$ and $CBL^{WMA + SAA}$

Comparison to Four NEBEF CBL Methods: Fig. 3.12

Table 3.7: Summary of the Established CBLs for the NEBEF (DR) Event Times Applying $CBL^{WMA} \cdot PAC$ and $CBL^{WMA} + SAA (W)$

2016-01-18				
	...	$t = 37$	$t = 38$...
Actual Load	...	982.11	999.89	...
$CBL^{WMA} \cdot PAC$...	985.02	1005.28	...
$CBL^{WMA} + SAA$...	979.73	997.39	...

With the following Figure 3.15 and Table 3.8 we can easily notice the subtle difference between the two CBL methods. Comparing the accuracy of the four CBL methods, it is a quite surprising improvement of the CBL method—MAPE and RRMSE were 12.21% and 14.94% respectively for $CBL^{avg.10}$ (Tab. 3.6), but this time MAPE and RRMSE are only 0.245% and 0.246% respectively for $CBL^{WMA} + SAA$ (Tab. 3.8). Among the two CBL methods, $CBL^{WMA} + SAA$ will be used for Sensitivity Analysis in the Chapter 4, Section 4.5.

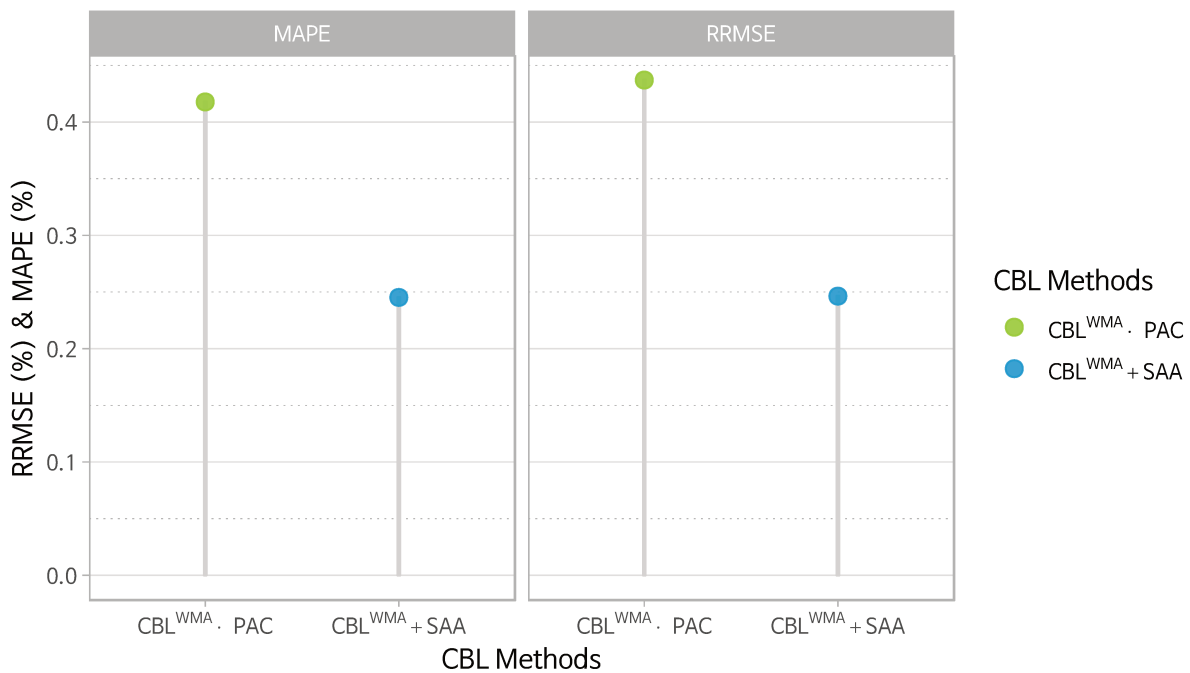


Figure 3.15: The CBL Accuracy Comparison (MAPE & RRMSE) between the Two CBL Methods of $CBL^{WMA} \cdot PAC$ and $CBL^{WMA} + SAA$

Comparison to the Accuracies of Four NEBEF CBL Methods: Fig. 3.13

Table 3.8: The CBL Accuracy Comparison (MAPE and RRMSE) between the Two CBL Methods of $CBL^{WMA} \cdot PAC$ and $CBL^{WMA} + SAA$

	$CBL^{WMA} \cdot PAC$	$CBL^{WMA} + SAA$
MAPE	0.418%	0.245%
RRMSE	0.437%	0.246%

In addition to the analyses of the CBL estimation methods focusing on the peak loads both for South Korea and France, that is the cross-validation between two different countries, in order to figure out whether or not the results hold true with different load profiles during different seasons in a country, that is the cross-validation between different seasons in a country, I have conducted supplementary analyses (in [Appendix A: Supplementary Figures & Tables](#) of this dissertation) with the different load profiles during winter for the South Korean case and summer for the French case this time. As a result, in the South Korean case, [Figure A.31](#), [Table A.9](#), [Figure A.32](#), and [Table A.10](#) show that the two CBL estimation methods with adjustment ($CBL^{WMA} \cdot PAC$ and $CBL^{WMA} + SAA$) outperform the two simple CBL estimation methods (CBL^{avg} and CBL^{WMA}). Even though $CBL^{WMA} \cdot PAC$ is slightly better than $CBL^{WMA} + SAA$, there is no significant difference between them.

In the French case, as can be seen in [Figure A.33](#), [A.34](#), [A.35](#), [Table A.11](#), [Figure A.36](#), and [Table A.12](#), all the four CBL estimation methods of NEBEF do not perform well again although the error rates are relatively small this time—about 4–5%. In contrast, the two CBL estimation methods of DRTM perform very well again—around 0.1% in terms of MAPE and RRMSE. With these supplementary analyses we could reconfirm that the two CBL estimation methods of DRTM are better than others, and it shows that the results are robust to the changes in load profiles of different seasons.

3.6 Conclusion

In Chapter 3, we found that the CBL estimation methods of South Korean DRTM, especially the two CBL methods of $CBL^{WMA} \cdot PAC$ and $CBL^{WMA} + SAA$, perform surprisingly very well with extremely low error rates about 0.5% while all the CBL estimation methods of NEBEF do not perform very well with high error rates about 12%–25%. In addition, when we applied the two CBL estimation methods of $CBL^{WMA} \cdot PAC$ and $CBL^{WMA} + SAA$ to the rescaled French average household load profile to establish the CBL, it resulted in a high performance with extremely low error rates less than 0.5% again. It is interesting and, at the same time, surprising that this simple statistical day matching CBL estimation method with an option is sufficient. In other words, very complex and advanced methods and a wide range of datasets are not essential in this case.

Furthermore, the results of the supplementary analyses of the different load profiles of different seasons are in line with the main results reconfirming that the two CBL estimation methods with adjustment ($CBL^{WMA} \cdot PAC$ and $CBL^{WMA} + SAA$) are the best even if load profiles are more stochastic and volatile. Therefore, this cross-validation between different seasons in a country added the robustness of the research. With the results, this study provides a country, in particular, France, with a meaningful policy implication to ameliorate the CBL estimation methods of NEBEF and ultimately the DR market design. The following Table 3.9 summarizes the results of the accuracy of CBL estimation methods in terms of MAPE and RRMSE. The gray cells highlight the best CBL estimation method with the smallest error rate.

Table 3.9: Overview of the Results: Accuracy of CBL Estimation Methods (MAPE & RRMSE)

	South Korea				France			
	Summer		Winter		Summer		Winter	
	2016-08-12		2016-01-21		2016-07-19		2016-01-18	
	MAPE	RRMSE	MAPE	RRMSE	MAPE	RRMSE	MAPE	RRMSE
$CBL^{avg.}$	9.21%	6.51%	6.34%	4.48%				
CBL^{WMA}	8.22%	5.81%	6.21%	4.39%				
$CBL^{WMA} \cdot PAC$	0.52%	0.37%	2.09%	1.48%	0.095%	0.101%	0.418%	0.437%
$CBL^{WMA} + SAA$	0.45%	0.32%	2.14%	1.52%	0.117%	0.125%	0.245%	0.246%
$CBL^{avg.10}$					4.36%	5.34%	12.21%	14.94%
$CBL^{med.10}$					3.37%	4.15%	13.30%	16.26%
$CBL^{avg.4}$					4.13%	5.03%	20.34%	24.89%
$CBL^{med.4}$					3.98%	4.86%	20.48%	25.03%

Like South Korean DRTM, the NEBEF mechanism is a quite recent market-oriented mechanism of DSM, so it is still evolving since the ‘Règles NEBEF 1’ in 2013. Even though it seems that RTE has tested many possible CBL estimation methods since the experimental phase, for example, the panel data analysis approach, it appears that RTE has not yet explicitly suggested or introduced the alternative options like PAC and SAA. According to the results of this research, the low performance and high error rates of the CBL estimation methods of NEBEF derived from the fact that it only relies on the simple average and median and does not use any adjustment options which could capture the recent changes of the load profile caused by whatever it is a temperature-based or socio-economic-based stochastic event.

As we have looked at the developing trends of both South Korean and French DR mechanisms in terms of the volume and frequency in Chapter 2, the importance of the NEBEF mechanism will be more significant with more intermittent RESs, the concern on climate change, sustainability, and security of electricity supply. In order to exploit the full-fledged DR mechanism in France, we need to pay more attention to the importance of accurate CBL estimation methods, which are the fundamental elements to encourage potential participants.

As we have observed, the currently utilized CBL estimation methods are likely to result in the underestimation of the CBLs, in turn, results in that the actual efforts or reductions will be underappreciated than it is. These inaccurate CBL methods could undermine the French NEBEF mechanism despite its advantage, such as the high-level openness of all the markets for the demand-side resources that we have found in Chapter 2.

Furthermore, it is expected that the accurate CBL estimation methods can prevent the participants from intentional and malicious manipulation of their CBLs. It is quite an important point from the DR system operator's or LA's perspective. If the CBL estimation methods are very accurate, then there will be little room for participants to strategically manipulate their CBLs in order to get remunerated much more than it should be. Only with these well-defined CBL estimation methods which can avoid the underestimation or overestimation as measurement error and the strategic countervailing incentives, the optimality of DR programs can be guaranteed.

Considering the above-mentioned policy implications, this study provides a good opportunity to shed light on and to compare the CBL estimation methods of South Korea and France each other. It is rare to see this kind of comparative analysis between countries focusing on the CBL estimation methods in practice. One of the difficulties to conduct this kind of research is that it is not easy to obtain the real-time load profiles of an individual level household due to the issues of privacy or information access. The approach in which we have used the rescaled load profile from the aggregate national loads enabled this analysis. Moreover, the simple mathematical model of linear algebra made it clearer and easier to understand the CBL calculation process and its analysis. Although this approach and the simple mathematical model of linear algebra were applied to the residential DR mechanism, they can be applied to other sectors, such as industrial and commercial DR programs because the approach and model used in this research are very generic. The very clear and distinct terms, simple but detailed equations and explanations will be helpful for further studies on CBLs in many countries which are actively developing DR mechanisms.

On top of that, this study and the estimated CBLs will be a stepping stone or foundation for the following analyses, such as the Decision-making Analysis based on CBA and SA in Chapter 4. Without this part on CBLs, it will be almost impossible to proceed to further researches or will face the ambiguity of DR mechanisms. Only based on the accurately estimated CBLs, the actual load reduction, optimal remuneration level, marginal disutility for participants with load shedding and load shifting, behavioral change of the participants (electricity consumption pattern with DR), the effectiveness of ToU tariff scheme, and so forth can be addressed in an appropriate way.

§Chapter 4

Cost-Benefit Analysis of Demand Response

4.1 Necessity of Cost-Benefit Analysis

One of the great barriers to the active implementations of DR was the uncertainty around the true costs and benefits of the programs (O'Connell et al., 2014, p. 688). Because the huge costs and investments for the infrastructure for information, communication, monitoring, and control system are required to realize DR programs, it is imperative that the costs and benefits of DR are clear (O'Connell et al., 2014, p. 688). Therefore, the precise estimation of the costs and benefits of DR has been the focus of energy economists (Bradley et al., 2013, p. 312). This view was shared by Strbac (2008, p. 4425) and Bruninx et al. (2013, p. 1) who point out that there needs to be a comprehensive analysis of costs and benefits of installing such a complicated infrastructure.

In addition, due to a lack of methodologies for the quantification of costs and benefits, there has not been enough clarity regarding the business model for DR. For this reason, significantly more research should be conducted in this area—CBA. Also, the CBA is closely related to the consideration of the ideal remuneration level. It is necessary first to estimate the exact value of the DR resources, that is, net benefits (costs – benefits), otherwise, it is impossible to define or set out the appropriate level of the remuneration for the DR resources.

The objective of a CBA is to evaluate whether or not there are net economic benefits associated with introducing a DRM under current circumstances (Hoch et al., 2014, p. 2).^[1] Therefore, it is useful for decision-makers to decide to introduce a DR program (approval of a DR program). Also, it can give them the information on the optimal timing and scope of DR programs. It can be also used for rate programs, such as ToU, CPP, and RTP, to determine whether or not a program, given a particular rate structure, is cost-effective (California Public Utilities Commission (CPUC), 2010, p. 5).

The CBA approach can provide us with a transparent and objective assessment of different options, which means, first of all, we consider whether or not changing the business as usual by implementing a certain option (“planning case”) is beneficial, and then, if there is more than one option, which option is more beneficial as compared to the business as usual case and the other options altogether. As a result, a CBA can be helpful for decision-makers to decide on one option based on transparent and objective criteria.

^[1] It is interesting that in the paper of Hoch et al. (2014, p. 3) they assess the impacts of DR by characterizing it as a ‘plant (or series of plants)’ based on the financial and operating characteristics of different types of DR.

4.2 Costs & Benefits to Be Considered and Previous CBAs

In the report of [He et al. \(2013, p. 5\)](#), they focused not only on the potential of financial incentives for DR, but also they searched for a wider set of costs and benefits for the consumers from the perspective of intermediaries and contracts. The report prepared by the [U.S. Department of Energy \(DOE\) \(2006, p. 74\)](#) also gives us an example of the CBA for the long-term market impacts of capacity benefits created by DR. In addition, it is interesting that [Bradley et al. \(2013\)](#) conducted a study on the review of the UK-specific costs and benefits of DR. [Covrig et al. \(2014, pp. 13–14, 90–92\)](#) analyzed the costs and benefits resulted from a nation-wide-roll-out of the smart metering system across the 27 European countries. As a result of the CBA, they could estimate that taking into account only the countries that had completed or were going to proceed with the roll-out of the smart metering system it was €223 (with a standard deviation of €143) for investment costs per smart metering point. In terms of the benefits, they expected that there could be peak load shifting of electricity consumption ranged from less than 1% to 9.9% and an average value of 3% (with a standard deviation of 1.3%) for energy savings (load shedding) in terms of electricity consumption. With this amount of the energy savings, the expected average benefit per metering point was €309 (with a standard deviation of €170) ([Covrig et al., 2014; European Commission \(EC\), 2014](#)).

When it comes to the benefits of DR, according to [Albadi and El-Saadany \(2008, p. 1991\)](#) we can think on the four different levels, such as participants, market-wide, reliability, and market performance. First of all, participants in DR programs can save their bills and receive incentive payments or direct payments in case of the IBPs. Also, we can expect an overall electricity price reduction as the DR drives out the most expensive electricity generating units, that is, marginal technology without DR. From the market-wide perspective, thanks to DR we can enjoy the benefit from the avoided or deferred capacity costs, reducing the environmental impacts of electricity production and infrastructure installations ([IEA, OECD, 2003, pp. 10–11](#)). Moreover, we can increase the reliability of the electric system because DR can play as flexibility resources. Finally, we can improve the electricity market performance (efficiency) overall.

In terms of the associated costs of DR, there are initial (investment) and running (operating) costs both for the DR program operator and participants. For initial costs, it needs to install some advanced technologies such as smart thermostats, peak load controls, energy management systems, AMI, ICT, and so forth. In terms of running costs, there are costs for the inconvenience, lost business, rescheduling, onsite generation for participants, administration, marketing, incentive payments, education, and evaluation costs for the program operator ([Albadi and El-Saadany, 2008, p. 1992](#)).

Based on the hierarchical market model (utility-aggregator-user interaction) ([Gkatzikis et al., 2013](#)), we can figure out the costs and benefits of DR at the three different levels: 1) utilities/RTO/ISO/DST/TSO, 2) LAs, and 3) consumers (participants = users = customers = clients) level.

First of all, at the level of utilities/ISO/RTO/TSO/DSOs, costs include the costs resulting from the installation of metering and communication infrastructures. Usually, suppliers are responsible for the procurement and the installation of smart meters as part of a mandatory smart meter roll-out, therefore these can be considered as system costs ([Bradley et al., 2013, p. 315](#)). The costs also include the remuneration to LAs for their services. The benefits for the supplier are savings on production costs, which is a reduction in costs, and substantial balancing during periods of high demand ([Fox-Penner, 2010](#)). Also, if the DR program operator is the system operators, it is the reduction of the operational costs. Therefore, the objective function of the utilities/ISO/RTO/TSO/DSOs can be the minimization of the system costs:

$$\min \{(\text{production costs}) + (\text{system costs for DR infrastructures}) + (\text{remuneration to LAs})\} \quad (4.1)$$

Secondly, at the level of LAs, costs include the incentives for end-users when the end-users respond to the call from LAs (or from the DR program operator) or when there were some direct load controls, curtailments or

interruptible ones, by LAs. Benefits include the remuneration paid by utilities/ISO/RTO/TSO/DSOs. Therefore, the objective function of LAs can be the profit maximization:

$$\max \{ (\text{remuneration paid by utilities/ISO/RTO/TSO/DSOs}) - (\text{incentives for end-users}) - (\text{operating costs}) \} \quad (4.2)$$

Lastly, at the level of consumers, costs mean the degree or the amount of inconvenience resulting from the change in their electricity consumption patterns. Benefits can be the reduced expenditure on electricity consumption, which means a reduced bill and incentives or direct payments. The main incentive for the consumer is the cost saving achieved by reducing demand or shifting to an off-peak period (Clastres, 2011, p. 5402). Therefore, in that sense, the objective function of customers could be the minimization of the electricity consumption expenditure considering the inconvenience, the cost-savings resulted from DR, and incentives or direct payments:

$$\min \{ (\text{electricity consumption expenditure}) + (\text{inconvenience}) - (\text{cost savings \& incentives from LAs}) \} \quad (4.3)$$

We have figured out the conceptual costs and benefits, and brief objective functions for each entity so far. However, when we conduct the calculation of a CBA we need to set a series of concrete assumptions and confirm the real (or monetary) value of the costs and benefits of DR. There were some studies on the estimation of the value of costs and benefit of DR (Bradley et al., 2013).

When it comes to the CBA frameworks, there were mainly two sources of the previous research on the CBA frameworks of the DR programs: firstly, it was the CBA on the DSM including EE and DR; secondly, it was the *Cost-Effectiveness Analysis (CEA)* on the SG which, of course, includes DR. The 'five cost-effectiveness tests', so-called 'California Tests'^[2], in the *California Standard Practice Manual (California Public Utilities Commission (CPUC), 2001, 2002, 2010)* and the researches conducted by FERC (Woolf et al., 2013) became the industrial standard. In the beginning, it was developed for EE, and then the framework was applied to DR programs later. Among the five tests of 'California Tests', this research focuses on the 'Participant Cost Test'. Therefore, there is a difference between this research and the previous researches of *California Public Utilities Commission (CPUC)* and FERC that this research is not for the comprehensive CBA like the 'Societal Cost Test'. It is said that 'Participant Cost Test' is useful for the improvement of the program design promoting the program participation (Woolf et al., 2013, p. v), so this CBA test and approach is appropriate for the research on the residential DRM of South Korea and France.

The U.S. by *Electric Power Research Institute (EPRI)* and EU^[3] by *Joint Research Centre (JRC)* have prepared well-elaborated frameworks for the CEA on the SG. *Electric Power Research Institute (EPRI)* (2010, 2011, 2012) suggested and explained the logic for the factors of benefits, the detailed steps of the CEA, and the criteria for it. EU JRC modified the frameworks developed by EPRI in the context of the EU and also provided the guidelines specialized in the deployment project of the Smart Meters (*Joint Research Centre (JRC), 2012a,b,c, 2016*). Although those are very valuable previous researches to refer, at the same time, there are differences in terms of the focus of the research that those are very comprehensive CEA because the SG is, in general,

^[2] In the 'California Tests', there are 'Participant Cost Test', 'Rate Impact Measure Test (RIM)', 'Program Administrator Cost Test', 'Total Resource Cost Test', and 'Societal Cost Test'.

^[3] In the Annex I of the Directive on Internal Markets (DIM) (*Council of European Union, 2009, p. L 211/91*), it is indicated that the Member States of the EU should fulfill the CEA on the implementation of intelligent metering systems by 3 September 2012 and prepare a timetable with a target of up to 10 years for this. In addition, in the case of the positive result of the CEA, at least 80% of consumers should be equipped with intelligent metering systems by 2020.

a very large scale project in the national level (except local or regional level microgrid) and it covers various categories in it.

Based on and referring to the previous frameworks for the CBA, the aim of this research is to provide DR program-related entities, especially DR system operators, with a decision-making framework based on the CBA in which the optimization (linear programming) is utilized in order to represent the rationality of the DR participants and to provide microeconomic explanations on DR participants' behaviors. In other words, we are going to figure out under what kind of conditions or circumstances a residential client participates in a DR program, how much loads does the client reduce or to which time slot does the client shift the electricity consumptions in order to minimize the costs. In addition, to take into consideration all the possible variations in terms of the key variables, the Monte Carlo simulation method will be utilized both for the Decision-making Analysis based on the CBA and its SA. Moreover, for the sake of convenience dealing with vast data and a number of repetitions of calculation, matrix algebra (linear algebra) is used as well as arithmetics.

4.3 CBA on South Korean Demand Resource Trading Market

4.3.1 A Model for the CBA

Based on the established CBL with the WMA + SAA option in Section 3.4 (Tab. A.15 in Appendix A: Supplementary Figures & Tables), we can proceed to the CBA for the residential participants (clients) of the DR program. In this section we set up a ‘reference scenario’, first in terms of the required load reduction, the different remuneration scheme, the proportion of the remuneration to participants, the cost function, the behaviors, constraints of the participant, and so forth, and then several different scenarios in which we set up different assumptions in terms of those factors will be dealt with in Section 4.5.

First of all, in terms of the required load reduction, we could assume 20%, 30% and 40% of the ‘Maximum Reducible Capacity’ for the DR event time. The ‘Maximum Reducible Capacity’ is defined as the difference between the CBL for the DR event time and the minimum base (‘MinBase’), that is, the fifth percentile hourly load during the maximum reference days (20 non-event and ordinary working days) prior to the DR event day (Lee et al., 2017). Looking at the cumulative density distribution of all the hourly load for the 20 maximum reference days, the fifth percentile is 482 (W) (Fig. 4.1 and Tab. 4.7). Figure 4.2 (and Tab. A.16 in Appendix A: Supplementary Figures & Tables) show the remaining load after 20% reduction, 30% reduction, 40% reduction, and after the maximum reducible capacities for the event times (one block consisting of two-time slots, $t = 17h$ and $t = 18h$).

$$\text{Maximum Reducible Capacity} = \text{CBL}_{t,d} - \text{MinBase} \quad (4.4)$$

where,

$$\left\{ \begin{array}{l} \text{MinBase} : \text{minimum base load defined as the fifth percentile of the cumulative density} \\ \text{distribution of all the hourly load for the maximum reference days (20 days} \\ \text{prior to the event day).} \end{array} \right.$$

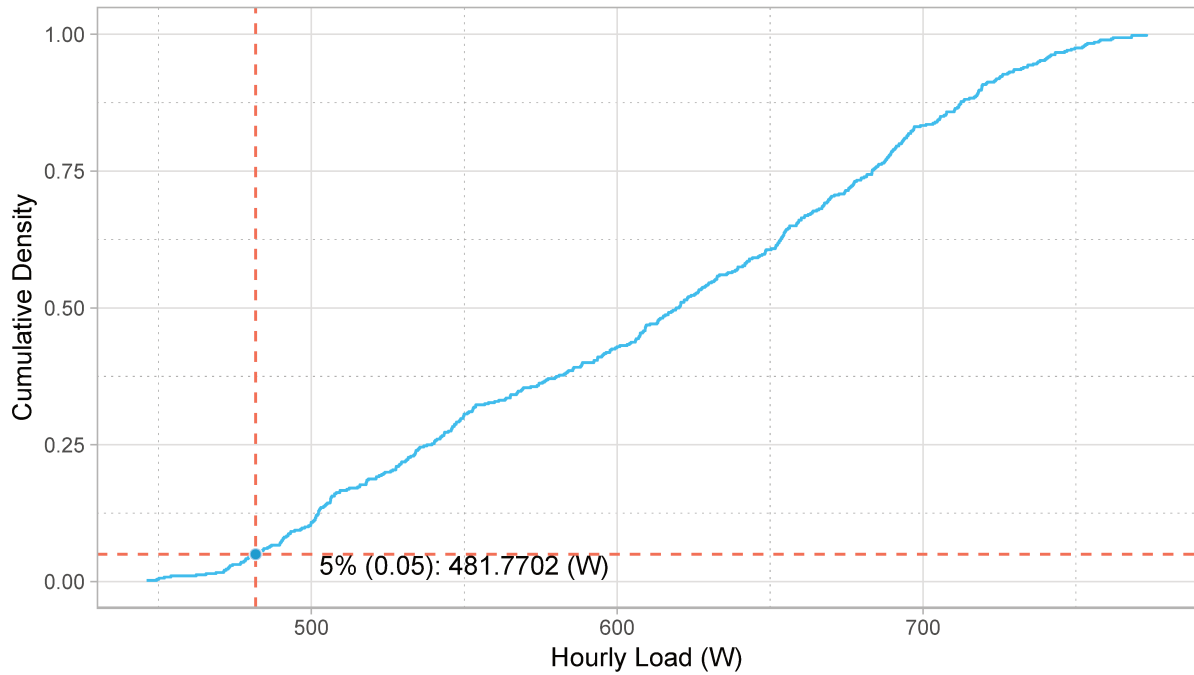


Figure 4.1: Cumulative Density Function of the Maximum Reference Days (20 days prior to Aug. 12, 2016)

Source: The original load data before rescaling, “대국민 전력수급현황 공유 시스템” (Public Information Sharing System on Electricity Demand and Supply), KPX, [On-line], Available: <https://openapi.kpx.or.kr/sukub.do#>

Table 4.1: The Percentiles of the Cumulative Density Function of the Maximum Reference Days (W)

0%	5%	25%	50%	75%	95%	100%
446	482	539	620	683	738	773

Source: The original load data before rescaling, “대국민 전력수급현황 공유 시스템” (Public Information Sharing System on Electricity Demand and Supply), KPX, [On-line], Available: <https://openapi.kpx.or.kr/sukub.do#>

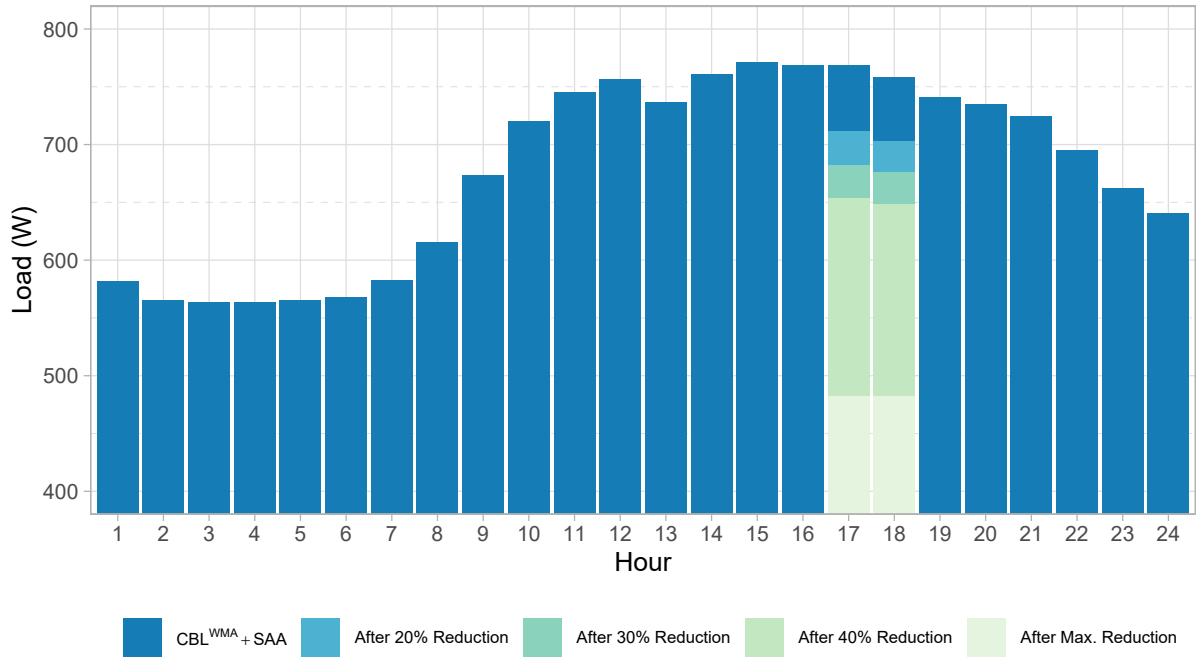


Figure 4.2: The Remained Loads according to the Required Load Reduction Level (20%, 30%, 40%, Max, and CBL) (W)

Comparison to French Case: Fig. 4.8

Next, in order to calculate the maximum profit, the **objective function** of the **optimization (linear programming)** (Eq. 4.5) is to maximize the net benefits of a residential participant, that is, to minimize the net costs for the electricity consumption. The decision variable is the column vector \mathbf{x} (Eq. 4.6) consisting of the proportions to the total required load reduction for $t = 17h$ and $t = 18h$ that will be shifted to other time slots except $t = 17h$ and $t = 18h$ themselves, and the **constraints** of the **optimization (linear programming)** (Eq. 4.7) are following. Note that in this research we are going to consider only the load shifting case for the South Korean DRTM, while we are going to consider both of the load shedding and load shifting case for the French NEBEF in which we can find the explicit distinction between the load shedding and the load shifting case.

$$\begin{aligned}
 \max_{\mathbf{x}} \Pi(\mathbf{x}; \phi, \mathbf{SMP}, \mathbf{r}', \mathbf{p}, \ell') &= B(\phi, \mathbf{SMP}, \mathbf{r}') - C(\mathbf{x}; \mathbf{p}, \ell') \\
 &= f_o(x_1, x_2, \dots, x_{24}; \phi, \mathbf{SMP}_{17}, \mathbf{SMP}_{18}, r'_{17}, r'_{18}) \\
 \text{or, } \min_{\mathbf{x}} C(\mathbf{x}) &= f_o(x_1, x_2, \dots, x_{24})
 \end{aligned} \tag{4.5}$$

where,

- \mathbf{x} : a column vector consisting of the proportions to the total required load reduction that will be shifted to other time slots, $t \in T = \{1, 2, \dots, 24\}$, except $t = 17h$ and $t = 18h$.
 ϕ : the proportion to SMP for a residential participant, therefore, the proportion to SMP for a LA is $(1-\phi)$,
 $0 \leq \phi \leq 1$
SMP : a vector of SMP,
 \mathbf{r}' : a vector of actualized load reduction,
 \mathbf{p} : retail price of electricity (tariff scheme),
 ℓ' : a column vector consisting of the actually consumed loads with DR for each time slot, $t \in T = \{1, 2, \dots, 24\}$,
 if we consider only load shifting, not load shedding, then the total electricity consumptions remain the same with DR event and without DR event, $\mathbf{1}_{24}^T \ell = \mathbf{1}_{24}^T \ell'$ that is, $\sum_{t=1}^{24} \ell_t = \sum_{t=1}^{24} \ell'_t$ where, $\mathbf{1}_{24}^T$ is a sum vector with all the elements of 1.

$$\mathbf{x} = x_t = \begin{pmatrix} x_1 \\ x_2 \\ \vdots \\ x_{17} \\ x_{18} \\ \vdots \\ x_{24} \end{pmatrix} \quad (4.6)$$

subject to the constraints,

$$\left\{ \begin{array}{l} \sum_{t=1}^{24} x_t = 1 \\ x_{17}, x_{18} = 0 \\ x_1, x_2, \dots, x_{16}, x_{19}, x_{20}, \dots, x_{24} \geq 0 \\ x_1, x_2, \dots, x_{16}, x_{19}, x_{20}, \dots, x_{24} \leq \frac{\text{Cap}_t}{(r_{17} + r_{18})} \cdot \ell_t \end{array} \right. \quad (4.7)$$

where,

- Cap** : a vector of the capacity factor, which represents the potential capacity to accept some part of the total required load reduction. In order to represent 'stochastic' capacity, individual property, daily conditions, it is 'random number' (pseudo-random number) from uniform distribution between 'o' and required flexibility level (RFL),
 $\mathbf{Cap} \sim U(0, \text{RFL})$
 $0 \leq \text{Cap}_t \leq \text{RFL}$
 $t \in T = \{1, 2, \dots, 24\}$
RFL : required flexibility level, such as, 0.2 (20%), 0.3 (30%), 0.4 (40%), or 1 (max).

The constraints in Equation 4.7 means that each element of the decision variable \mathbf{x} should be equal to or greater than 0 except for the time slots of the DR event. If x_{17} and x_{18} are greater than 0, it means the partial

fulfillment of the order or call from the DR system operator. In addition, the total sum of all the elements of the decision variable \mathbf{x} should be equal to 1 because those are the proportions to the total reductions of the DR event. The variable **Cap** represents a vector of the capacity factor. $x_t \times (r_{17} + r_{18})$ represents the amount which will be shifted to that time slot. I assume that the actual load for each time slot without the DR event has some information on how much this time slot can accommodate more. Therefore, $\text{Cap}_t \times \ell_t$ represents the capacity to accommodate some part of the reduction which will be shifted to that time slot. In general, it is difficult to estimate or determine this kind of capacity to accommodate for each time slot because each individual has different conditions or environments depending on time, day, month, season, and many other variables. Considering this aspect, I have set this factor as a stochastic variable using the variable **Cap** which can be a random number randomly selected from the uniform distribution. Again, I have synchronized the upper bound (maximum value) for the variable **Cap** with the required flexibility level (RFL). From the DR system operator's perspective, if the DR system operator assumes that DR participants have higher flexibility (that is, with higher capacity to accommodate the shifted loads), then the DR system operator will call for higher required flexibility level, and vice versa.

The required load reductions are non-negative ($r_t \in \mathbb{R}_+$) for the DR event times, $t = 17h$ and $t = 18h$, and '0' (zero) for the other time slots.

$$\mathbf{r} = r_t = \begin{pmatrix} r_1 \\ \vdots \\ r_{16} \\ r_{17} \\ r_{18} \\ r_{19} \\ \vdots \\ r_{24} \end{pmatrix} = \begin{pmatrix} 0 \\ \vdots \\ 0 \\ r_{17} \\ r_{18} \\ 0 \\ \vdots \\ 0 \end{pmatrix} \quad (4.8)$$

where,

$$\left\{ \begin{array}{l} \mathbf{r} : \text{ a column vector consisting of the required load reductions for each time} \\ \text{ slots, especially, for the event times,} \\ r_{17} \geq 0, r_{18} \geq 0, r_1 = r_2 = \dots = r_{16} = r_{19} = \dots = r_{24} = 0. \end{array} \right.$$

For example, we can define \mathbf{r}^{20} , \mathbf{r}^{30} , \mathbf{r}^{40} for the required load reduction vector when the required flexibility is 20%, 30%, and 40%, respectively.^[4]

^[4] In the following CBAs, we are going to assume 40% for the required flexibility. In terms of the rationale for assuming the required flexibility of 40%, it could seem to be a very ad-hoc or arbitrary assumption. We have not conducted SAs on this variable in this research because this flexibility level seems to be relatively less critical than other key variables. We could expect the different results of CBAs with different required flexibility levels. It might depend on net unit benefits of the CBA model. If net unit benefits are negative, then with higher required flexibility level, it will decrease the net benefits accumulating negative benefits. If net unit benefits are positive, then with higher required flexibility level, it will increase the net benefits accumulating positive benefits. It will be interesting to conduct SAs in practice on various flexibility levels in order to figure out this expectation.

$$\mathbf{r}^{20} = \begin{pmatrix} 0 \\ \vdots \\ 0 \\ 57.73 \\ 55.76 \\ 0 \\ \vdots \\ 0 \end{pmatrix}, \mathbf{r}^{30} = \begin{pmatrix} 0 \\ \vdots \\ 0 \\ 86.59 \\ 83.64 \\ 0 \\ \vdots \\ 0 \end{pmatrix}, \mathbf{r}^{40} = \begin{pmatrix} 0 \\ \vdots \\ 0 \\ 115.45 \\ 111.52 \\ 0 \\ \vdots \\ 0 \end{pmatrix}$$

The actually consumed loads without the DR event, which means '0' (zero) reduction for $t = 17h$ and $t = 18h$.

$$\boldsymbol{\ell} = \ell_t = \begin{pmatrix} \ell_1 \\ \ell_2 \\ \vdots \\ \ell_{17} \\ \ell_{18} \\ \vdots \\ \ell_{24} \end{pmatrix} \quad (4.9)$$

where,

$$\left\{ \begin{array}{l} \boldsymbol{\ell} : \text{ a column vector consisting of the actually consumed loads for each time slot,} \\ t \in T = \{1, 2, \dots, 24\}. \end{array} \right.$$

This actually consumed loads will change when there is a DR event, therefore there will be reductions for $t = 17h$ and $t = 18h$ and possible increases for other time slots shifted from $t = 17h$ and $t = 18h$.

$$\begin{aligned} \boldsymbol{\ell}' = \ell'_t = \begin{pmatrix} \ell'_1 \\ \ell'_2 \\ \vdots \\ \ell'_{17} \\ \ell'_{18} \\ \vdots \\ \ell'_{24} \end{pmatrix} &= \boldsymbol{\ell} - \mathbf{r} + (r_{17} + r_{18})\mathbf{x} \\ &= \begin{pmatrix} \ell_1 \\ \vdots \\ \ell_{16} \\ \ell_{17} \\ \ell_{18} \\ \ell_{19} \\ \vdots \\ \ell_{24} \end{pmatrix} - \begin{pmatrix} 0 \\ \vdots \\ 0 \\ r_{17} \\ r_{18} \\ 0 \\ \vdots \\ 0 \end{pmatrix} + (r_{17} + r_{18}) \begin{pmatrix} x_1 \\ \vdots \\ x_{16} \\ 0 \\ 0 \\ x_{19} \\ \vdots \\ x_{24} \end{pmatrix} \end{aligned} \quad (4.10)$$

Let us define \mathbf{CBL}' in which all the elements are '0' (zero) except 17th and 18th elements, and those are CBL_{17} and CBL_{18} , respectively,

$$\mathbf{CBL}' = \begin{matrix} 1 \\ 2 \\ \vdots \\ 17 \\ 18 \\ \vdots \\ 24 \end{matrix} \begin{pmatrix} 0 \\ 0 \\ \vdots \\ CBL_{17} \\ CBL_{18} \\ \vdots \\ 0 \end{pmatrix} \quad (4.11)$$

and, ℓ'' (double prime of ℓ) in which all the elements are '0' (zero) except 17th and 18th elements, and those are ℓ'_{17} and ℓ'_{18} , respectively.

$$\ell'' = \begin{pmatrix} 0 \\ 0 \\ \vdots \\ \ell'_{17} \\ \ell'_{18} \\ \vdots \\ 0 \end{pmatrix} = \begin{pmatrix} 0 \\ 0 \\ \vdots \\ \ell_{17} \\ \ell_{18} \\ \vdots \\ 0 \end{pmatrix} - \begin{pmatrix} 0 \\ 0 \\ \vdots \\ r_{17} \\ r_{18} \\ \vdots \\ 0 \end{pmatrix} \quad (4.12)$$

Note that the required load reduction \mathbf{r} and actualized load reduction \mathbf{r}' are different. For the required load reduction \mathbf{r} , the residential participant will reduce this amount from the original load (ℓ_{17} , ℓ_{18}). Then, the actualized load reduction \mathbf{r}' can be calculated:

$$\mathbf{r}' = \mathbf{CBL}' - \ell'' = \begin{pmatrix} 0 \\ 0 \\ \vdots \\ CBL_{17} \\ CBL_{18} \\ \vdots \\ 0 \end{pmatrix} - \begin{pmatrix} 0 \\ 0 \\ \vdots \\ \ell'_{17} \\ \ell'_{18} \\ \vdots \\ 0 \end{pmatrix} = \begin{pmatrix} 0 \\ 0 \\ \vdots \\ r'_{17} \\ r'_{18} \\ \vdots \\ 0 \end{pmatrix} \quad (4.13)$$

where,

$$\left\{ \begin{array}{l} \ell' : \text{ a column vector consisting of the actually consumed loads with DR for each} \\ \text{ time slot, } t \in T = \{1, 2, \dots, 24\}, \\ \text{ if we consider only load shifting, not load shedding, then the total electric-} \\ \text{ ity consumptions remain the same with DR event and without DR event,} \\ \mathbf{1}^T \ell = \mathbf{1}^T \ell' \text{ that is, } \sum_{t=1}^{24} \ell_t = \sum_{t=1}^{24} \ell'_t. \end{array} \right.$$

With this Equation 4.13, we can mathematically and systemically explain again the importance of accurate CBLs and their estimation methods. The participants will be paid for this actualized load reduction, but if the CBLs are underestimated with inaccurate CBL calculating methods, then it will result in the underestimation

of the actualized load reductions than it is. Therefore, this inaccurate CBLs and CBL estimation methods will drive out the participants with decreasing motivation.

For the actualized load reduction the participant will be remunerated at the level of SMP in the wholesale market in South Korea. Therefore, the benefits from the remuneration will be the following (Eq. 4.14):

$$B(\phi, \mathbf{SMP}, \mathbf{r}') = \phi \cdot \mathbf{SMP}^T \cdot \mathbf{r}' = \phi \begin{pmatrix} \text{SMP}_1 & \text{SMP}_2 & \dots & \text{SMP}_{24} \end{pmatrix} \begin{pmatrix} 0 \\ 0 \\ \vdots \\ r'_{17} \\ r'_{18} \\ \vdots \\ 0 \end{pmatrix} \quad (4.14)$$

where,

$$\begin{cases} \phi & : \text{ the proportion to SMP for a residential participant, therefore, the proportion to SMP for a load aggregator is } (1-\phi), \\ & 0 \leq \phi \leq 1 \\ \mathbf{SMP} & : \text{ a vector of SMP.} \end{cases}$$

Let us assume '1' as a default value for ϕ which means that all the remuneration will be paid for the residential participant, and there is no gain divided for the LA. This is one of the assumptions setting the maximum level of the remuneration for a residential participant. In the real world, it will be between 0 and 1 and will be determined by the contract between an LA and DR participants considering the operating costs, transaction costs, margins for the LAs, and so forth.

Figure 4.3^[5] shows the time series data of SMP in South Korea, 2016. In winter, especially in Jan., Feb., and Mar. it is relatively high and in August it is the lowest on average—also, in general, lower variability [relatively small standard deviation (**Std.Dev**) in Tab. 4.2 and shorter interquartile range (**IQR**) in Fig. 4.4] of SMP compared to that of France. The gradation color bar from blue to yellow means the average SMP in a month and the dashed green line throughout the entire year means the annual average SMP, that is 76.39 Korean Won (₩)/kWh in 2016 (100.59 Korean Won (₩)/kWh in 2015 in Fig. A.28).

^[5] You can find Figure A.28 which shows the time series data of SMP in South Korea, 2015 in [Appendix A: Supplementary Figures & Tables](#).

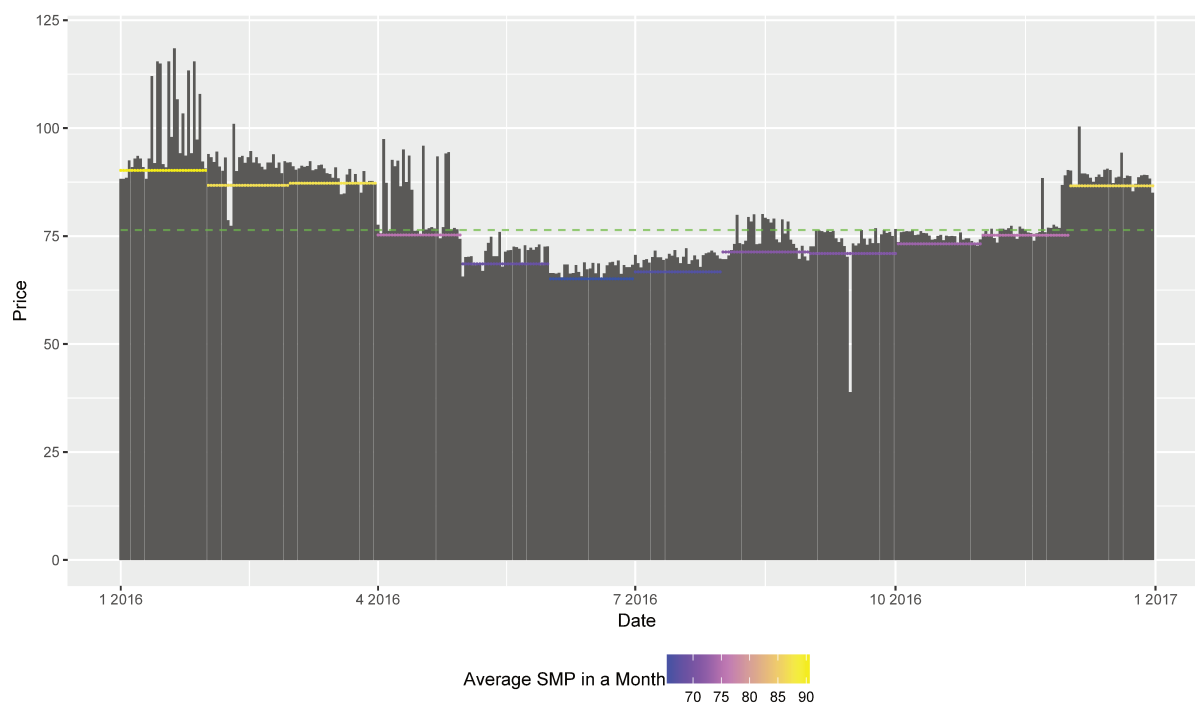


Figure 4.3: SMP, South Korea in 2016 (Korean Won (₩)/kWh)

Source: "SMP". KPX, [On-line], Available: <http://www.kpx.or.kr/www/contents.do?key=225>

Comparison to France: Fig. 4.9

Table 4.2: Descriptive Statistics of SMP in 2015, 2016 (South Korea)

	2015	2016
Mean	100.17	76.14
Std.Dev	19.87	10.52
Min	36.37	34.54
Q1	90.06	69.42
Median	96.63	74.06
Q3	106.86	86.43
Max	151.35	118.46
MAD	10.97	9.52
IQR	16.79	17.01
CV	0.20	0.14
Skewness	-0.02	-0.21
SE.Skewness	0.03	0.03
Kurtosis	1.46	1.21
N.Valid	8760.00	8784.00
Pct.Valid	100.00	100.00

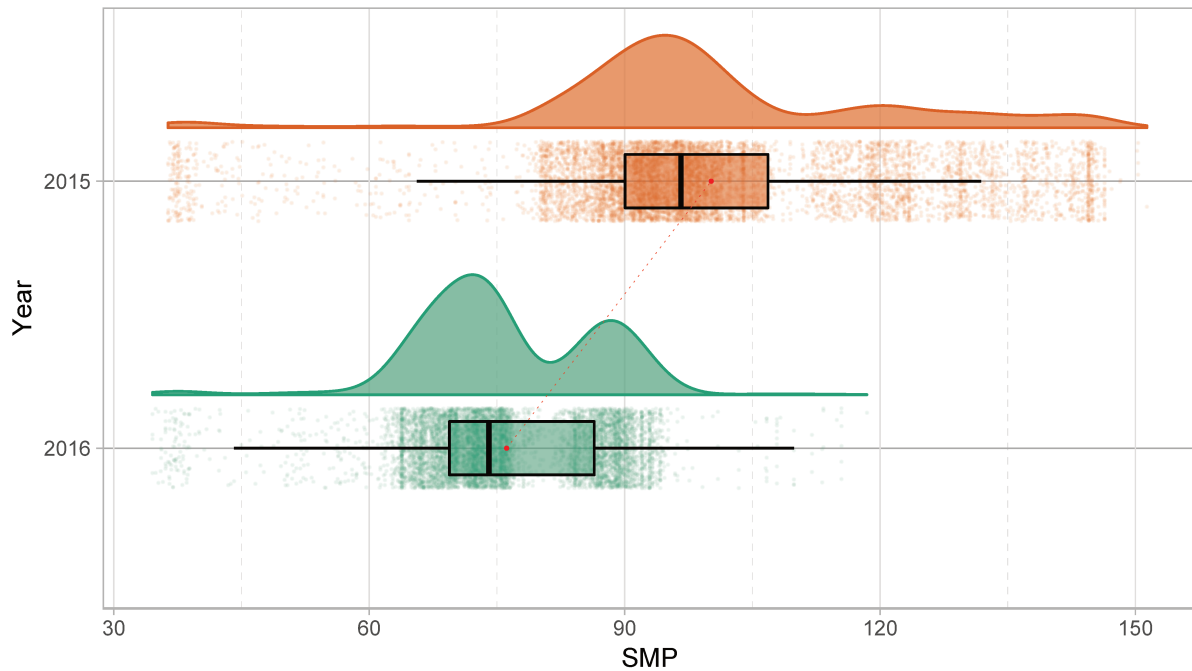


Figure 4.4: Raincloud Plots of SMPs in 2015, 2016 (South Korea, ₩/ kWh)

Credit for *Raincloud Plots*: Allen et al. (2018, 2019)

Focusing on the hourly SMPs for $t = 17h$ and $t = 18h$ on Friday, August 12, 2016 in South Korea, it was the following (Tab. 4.3):

Table 4.3: The SMP for the Event Times (₩/Wh)

2016-08-12				
	...	17h	18h	...
SMP	...	0.08005	0.07869	...

Source: "SMP", KPX, [On-line], Available: <http://www.kpx.or.kr/www/contents.do?key=225>

If there is no DR event and no required reduction, the remuneration will be zero, '0' because $r_t = 0$, where, $t \in T = \{1, 2, \dots, 24\}$.

$$C(\mathbf{x}) = \text{Total Tariff} + \text{additional inconvenience costs (INC)} \quad (4.15)$$

When it comes to the first part of the cost function (Eq. 4.15), that is the 'Total Tariff', if a residential participant contracted the uniform tariff scheme, the unit electricity price for each hour will be the same (constant, $p_t = c$) throughout a day. If a residential participant contracted the ToU tariff scheme^[6], the

^[6] Actually, there is no ToU tariff scheme for residential clients in South Korea yet. However, in order to do SAs in terms of tariff schemes, I have referred to the ToU tariff scheme for industrial and commercial clients. According to the '2nd Master Plan for Smart Grids (2018–2022)' announced in August 2018, the South Korean government is planning to expand the ToU tariff scheme for households, and to that end, it is now running the pilot program with 2,000 households until 2020.

retail price varies depending on time, day, and season (Tab. 4.5, 4.6 and Eq. 4.17).

$$\mathbf{p}^u = p_t^u = \begin{pmatrix} c \\ c \\ \vdots \\ c \end{pmatrix}, \quad \mathbf{p}^{\text{tou}} = p_t^{\text{tou}} = \begin{pmatrix} p_1 \\ p_2 \\ \vdots \\ p_{24} \end{pmatrix} \quad (4.16)$$

where,

$$\begin{cases} \mathbf{p}^u & : \text{ a column vector consisting of the retail price with uniform tariff scheme for} \\ & \text{ each time slot, } t \in T = \{1, 2, \dots, 24\}, \\ \mathbf{p}^{\text{tou}} & : \text{ a column vector consisting of the retail price with Time-of-Use tariff scheme} \\ & \text{ for each time slot, } t \in T = \{1, 2, \dots, 24\}. \end{cases}$$

Table 4.4 shows the unit retail price for residential usage from 2011 to 2015 in Korea. For the uniform price scheme we will take the latest price at 124 Korean Won, ₩/ kWh (that is, 0.124 Won, ₩/Wh).

Table 4.4: The Unit Retail Price for Residential Usage (Korean Won, ₩/ kWh)

2011	2012	2013	2014	2015
120	124	127	125	124

Source: “판매단가” (Unit Retail Price), Electric Power Statistics Information System (EPSIS), [On-line], Available: <http://epsis.kpx.or.kr/epsisnew/selectEksaScfGrid.ajax?menuId=060700>

Table 4.5: Different Time Periods for Peak and Off-Peak Periods (South Korea)

	Summer	Spring · Autumn	Winter
(off-peak) light load period	23:00-09:00	23:00-09:00	23:00-09:00
	09:00-10:00	09:00-10:00	09:00-10:00
(off-peak) medium load period	12:00-13:00	12:00-13:00	12:00-17:00
	17:00-23:00	17:00-23:00	20:00-22:00
	10:00-12:00	10:00-12:00	10:00-12:00
peak load period	13:00-17:00	13:00-17:00	17:00-20:00
			22:00-23:00

Source: KEPCO, [On-line], Available: <http://cyber.kepco.co.kr/ckeppo/front/jsp/CY/D/C/CYDCHP00403.jsp>

Table 4.6: ToU Tariff Scheme (South Korea, ₩/Wh)

	Summer	Spring · Autumn	Winter
(off-peak) light load period	0.0627	0.0627	0.0714
(off-peak) medium load period	0.1139	0.0701	0.1018
peak load period	0.1364	0.0814	0.1166

Source: KEPCO, [On-line], Available: <http://cyber.kepco.co.kr/ckeppo/front/jsp/CY/D/C/CYDCHP00401.jsp>

$$\mathbf{p}^{\text{tou}} = \begin{matrix} t & p_t^{\text{tou}} \\ 1 & 0.0714 \\ \vdots & \vdots \\ 9 & 0.0714 \\ 10 & 0.1018 \\ 11 & 0.1166 \\ 12 & 0.1166 \\ 13 & 0.1018 \\ \vdots & \vdots \\ 17 & 0.1018 \\ 18 & 0.1166 \\ 19 & 0.1166 \\ 20 & 0.1166 \\ 21 & 0.1018 \\ 22 & 0.1018 \\ 23 & 0.1166 \\ 24 & 0.0714 \end{matrix} \quad (4.17)$$

The total tariff for a day will be the scalar (or dot, inner) product of the retail price vector (transposed) and the actual consumption load, $\mathbf{p}' \times \mathbf{l}$. The total tariff accounts for the total costs if there is no DR event, however, if there is a DR event, the total tariff accounts for a part of the total costs for a residential participant.

Total tariff with a uniform tariff scheme without DR event:

$$\text{Total Tariff} = (\mathbf{p}^{\text{u}})^{\text{T}} \cdot \boldsymbol{\ell} = \begin{pmatrix} c & c & \dots & c \end{pmatrix} \begin{pmatrix} \ell_1 \\ \ell_2 \\ \vdots \\ \ell_{24} \end{pmatrix} \quad (4.18)$$

Total tariff with Time-of-Use tariff scheme without DR event:

$$\text{Total Tariff} = (\mathbf{p}^{\text{tou}})^{\text{T}} \cdot \boldsymbol{\ell} = \begin{pmatrix} p_1 & p_2 & \dots & p_{24} \end{pmatrix} \begin{pmatrix} \ell_1 \\ \ell_2 \\ \vdots \\ \ell_{24} \end{pmatrix} \quad (4.19)$$

Total tariff with a uniform tariff scheme with DR:

$$\text{Total Tariff} = (\mathbf{p}^{\text{u}})^{\text{T}} \cdot \boldsymbol{\ell}' = \begin{pmatrix} c & c & \dots & c \end{pmatrix} \begin{pmatrix} \ell'_1 \\ \ell'_2 \\ \vdots \\ \ell'_{24} \end{pmatrix} \quad (4.20)$$

Total tariff with Time-of-Use tariff scheme with DR:

$$\text{Total Tariff} = (\mathbf{p}^{\text{tou}})^T \cdot \boldsymbol{\ell}' = \begin{pmatrix} p_1 & p_2 & \dots & p_{24} \end{pmatrix} \begin{pmatrix} \ell'_1 \\ \ell'_2 \\ \vdots \\ \ell'_{24} \end{pmatrix} \quad (4.21)$$

On top of the total tariff for electricity consumption, we need to consider the additional inconvenience costs due to the load shifting. In order to meet the order or call from the DR system operator, a participant might have to postpone cooking, washing or might suffer from extreme hot or cold weather conditions for a while. The concept of the additional inconvenience costs is very subjective because it can be different for each person depending on one's economic or financial, daily, psychological, time-specific conditions, a value judgment, and so forth. In this regard, determining the unit value of the additional inconvenience costs for the shifted load reduction is difficult. To overcome this problem, we can rely on more objective value, that is, the price for electricity consumption. The present value per one unit of the reduced electricity consumption for $t = 17h$ and $t = 18h$ is p_{17} , p_{18} , respectively—and it is $(p_{17} + p_{18})/2$ when we use the average value for $t = 17h$ and $t = 18h$ if those are different because of ToU tariff scheme.^[7] This unit value is equivalent to the *Willingness-to-Accept (WTA)* for the inconvenience to shift one's as usual load.

In terms of this cost for the inconvenience, we can think of two cases. In the first case, we can assume the same value per one unit electricity consumption shifted even if it is shifted to other time slots regardless of the time distance (interval). In this case, the residential participant appreciates the same unit value for the inconvenience. It does not mean that there are no additional costs due to inconvenience on top of the total tariff for the actual consumption. In the second case, the costs of inconvenience will be increasing linearly or exponentially as the time distance (interval) increases.

$$\mathbf{d} = d_t = \begin{pmatrix} d_1 \\ d_2 \\ \vdots \\ d_{16} \\ d_{17} \\ d_{18} \\ d_{19} \\ \vdots \\ d_{24} \end{pmatrix} = \begin{pmatrix} 16 \\ 15 \\ \vdots \\ 1 \\ 0 \\ 0 \\ 1 \\ \vdots \\ 6 \end{pmatrix} \quad (4.22)$$

^[7] This average value is for the case of ToU. If it is uniform tariff there is no difference between the actual mono-price and the average value. Therefore, if there is only the uniform tariff case, we do not need to come up with this concept of an average value for the additional inconvenience costs. However, when it is a ToU tariff scheme, determining the unit value of the additional inconvenience costs for the shifted load reduction can be a little bit complicating. Let me give you an example. If we reduce 100 w at $t = 17h$ and 100 w at $t = 18h$, and shift this each reduction to $t = 19h$ and $t = 20h$, respectively, that is 100 w from $t = 17h$ to $t = 19h$, and 100 w from $t = 18h$ to $t = 20h$. In this case, we can use each price data for each time slot for $t = 17h$ and $t = 18h$. However, it is not always the case. We reduce the same amount, 100 w at $t = 17h$ and 100 w at $t = 18h$, and then for this 200 w reduction, we shift 110 w (50 w from $t = 17h$ and 60 w from $t = 18h$) to $t=19$ and 90 w (50 w from $t = 17h$ and 40 w from $t = 19h$) to $t = 20h$ —which means the shifted load reduction might consist of mixed loads of the two time slots. In this case, which value do we have to set as the unit value of the inconvenience costs for 110 w to $t = 19h$ and 90 w to $t = 20h$? Moreover, in general, it would be difficult to distinguish exactly which load reduction from one of the time slots of the DR event period goes to which time slot. Therefore, calculating an average value for the unit value of the additional inconvenience costs makes the calculation and analysis simple and convenient.

where,

$$\left\{ \begin{array}{l} \mathbf{d} : \text{ a vector of time distance from DR event time to shifted time slot, } t \in T = \\ \{1, 2, \dots, 24\}. \end{array} \right.$$

For example, the unit value for the shifted load is proportional to the time distance from the time block to the shifted time slots. If a part of the load reduction is shifted to the time slot $t = 1h$ $[(r_{17} + r_{18}) \times x_1]$, the time distance is 16 ($d_1 = 16$), and the unit value for the shifted load in terms of inconvenience will be much bigger than that of the load shift to the time slot $t = 16h$, just before the DR event time or the time slot $t = 19h$, just after the DR event time. Of course, if there is no DR event, this kind of inconvenience costs will not bring about at all.

In the following equations, β represents the relative ratio of inconvenience to the unit present value of the electricity consumption at the DR event time. This subjectively perceived β value can vary from person to person. In the following CBA models, we first assume a $\beta = 0.5$. The implication of a $\beta = 0.5$ is that a customer appreciates his/her additional inconvenience costs at the level of one half of the unit present value of the electricity consumption at the DR event time. In order to cover different levels of β values, we are going to conduct SAs at the end of this chapter from 0.5 to 1.5 increasing by 0.1.

$$INC_t = \beta \frac{(p_{17} + p_{18})}{2} d_t (r_{17} + r_{18}) x_t$$

$$INC = \begin{pmatrix} INC_1 \\ INC_2 \\ \vdots \\ INC_{24} \end{pmatrix} = \beta \frac{(p_{17} + p_{18})}{2} (r_{17} + r_{18}) \cdot \text{diag}(\mathbf{d} \otimes \mathbf{x}) \quad (4.23)$$

where,

$$\left\{ \begin{array}{l} INC_t : \text{ additional inconvenience costs,} \\ \quad \quad \quad t \in T = \{1, 2, \dots, 24\}, \\ \beta : \text{ the relative ratio of inconvenience to the unit present value of the electricity} \\ \quad \quad \quad \text{consumption at the DR event time,} \\ \frac{(p_{17} + p_{18})}{2} : \text{ the average retail price for 17h and 18h,} \\ d_t : \text{ time distance from DR event time to shifted time slot,} \\ \quad \quad \quad t \in T = \{1, 2, \dots, 24\}, \\ x_t : \text{ proportion to the total load reduction,} \\ \quad \quad \quad t \in T = \{1, 2, \dots, 24\}, \\ \text{diag}(\cdot) : \text{ a column vector consisting of diagonal elements,} \\ \mathbf{d} \otimes \mathbf{x} : \text{ outer product of the two vectors.} \end{array} \right.$$

$$\begin{aligned}
\mathbf{d} \otimes \mathbf{x} = \mathbf{d} \cdot \mathbf{x}^T &= \begin{pmatrix} d_1 \\ d_2 \\ \vdots \\ d_{24} \end{pmatrix} \begin{pmatrix} x_1 & x_2 & \dots & x_{24} \end{pmatrix} \\
&= \begin{pmatrix} d_1x_1 & d_1x_2 & \dots & d_1x_{24} \\ d_2x_1 & d_2x_2 & \dots & d_2x_{24} \\ \vdots & \vdots & \ddots & \vdots \\ d_{24}x_1 & d_{24}x_2 & \dots & d_{24}x_{24} \end{pmatrix} \\
diag(\mathbf{d} \otimes \mathbf{x} = \mathbf{d} \cdot \mathbf{x}^T) &= \begin{pmatrix} d_1x_1 \\ d_2x_2 \\ \vdots \\ d_{24}x_{24} \end{pmatrix}
\end{aligned}$$

$$\text{Total INC} = \beta \frac{(p_{17} + p_{18})}{2} (r_{17} + r_{18}) \mathbf{d}^T \cdot \mathbf{x} \quad (4.24)$$

In terms of the increasing rate of the unit value of shifted load can be a constant, which means this inconvenience costs function is a linear model, and can also be quadratic or exponential in terms of the time distance, \mathbf{d} . The following is one of the possible linear inconvenience cost models with $\beta = 0.5$.^[8]

$$\text{Total INC} = 0.5 \times \frac{(p_{17} + p_{18})}{2} (r_{17} + r_{18}) \mathbf{d}^T \cdot \mathbf{x}$$

In summary, the functions for the total benefits and total costs are the following:

$$\begin{cases} B_1(\phi, \mathbf{SMP}, \mathbf{r}') = \phi \cdot \mathbf{SMP}^T \cdot \mathbf{r}' \\ C_1(\mathbf{x}; \mathbf{p}, \ell') = \mathbf{p}^T \cdot \ell' + \beta \frac{(p_{17} + p_{18})}{2} (r_{17} + r_{18}) \mathbf{d}^T \cdot \mathbf{x} \end{cases}$$

$$\begin{aligned}
C_1(\mathbf{x}; \mathbf{p}, \ell') &= \mathbf{p}^T \cdot \ell' + \beta \frac{(p_{17} + p_{18})}{2} (r_{17} + r_{18}) \mathbf{d}^T \cdot \mathbf{x} \\
&= \mathbf{p}^T \cdot \{ \ell - \mathbf{r} + (r_{17} + r_{18}) \cdot \mathbf{x} \} + \beta \frac{(p_{17} + p_{18})}{2} (r_{17} + r_{18}) \mathbf{d}^T \cdot \mathbf{x} \\
&= \{ \mathbf{p}^T \cdot (\ell - \mathbf{r}) + (r_{17} + r_{18}) \mathbf{p}^T \cdot \mathbf{x} \} + \beta \frac{(p_{17} + p_{18})}{2} (r_{17} + r_{18}) \mathbf{d}^T \cdot \mathbf{x} \\
&= \underbrace{\mathbf{p}^T \cdot (\ell - \mathbf{r})}_{\text{scalar}} + (r_{17} + r_{18}) \underbrace{\left\{ \mathbf{p}^T + \beta \frac{(p_{17} + p_{18})}{2} \mathbf{d}^T \right\}}_{\text{optimization: } \min_{\mathbf{x}} \text{ Cost}} \cdot \mathbf{x}
\end{aligned}$$

In the case of no DR event (status quo),

^[8] 

$$\text{INC}_t = 0.5 \times \frac{(p_{17} + p_{18})}{2} d_t (r_{17} + r_{18}) x_t \quad (4.25)$$

$$\begin{cases} B_0(\phi, \mathbf{SMP}, \mathbf{r}') = \phi \cdot \mathbf{SMP}^T \cdot \mathbf{r}' = 0 \\ C_0(\mathbf{p}, \ell) = \mathbf{p}^T \cdot \ell \end{cases}$$

4.3.2 Decision-making Analysis for South Korean DRTM

If the total profit of a residential client with participation in a DR program is greater than the total profit of him/her without participation in a DR program, the residential client will participate in the DR program. It is the basic idea of decision-making based on the Cost-Benefit Analysis.

$$\max_{\mathbf{x}} \Pi_1(\mathbf{x}; \phi, \mathbf{r}') - \max_{\mathbf{x}} \Pi_0(\mathbf{x}; \phi, \mathbf{r}') > 0$$

$$\begin{aligned} & \{B_1(\phi, \mathbf{r}', \mathbf{SMP}) - C_1(\mathbf{x}; \mathbf{p}, \ell')\} - \{B_0(\phi, \mathbf{r}', \mathbf{SMP}) - C_0(\mathbf{p}, \ell)\} > 0 \\ \Rightarrow & \{B_1(\phi, \mathbf{r}', \mathbf{SMP}) - B_0(\phi, \mathbf{r}', \mathbf{SMP})\} - \{C_1(\mathbf{x}; \mathbf{p}, \ell') - C_0(\mathbf{p}, \ell)\} > 0 \end{aligned}$$

$$(\phi \cdot \mathbf{SMP}^T \cdot \mathbf{r}' - 0) - \left[\left\{ \mathbf{p}^T \cdot \ell' + \beta \frac{(p_{17} + p_{18})}{2} (r_{17} + r_{18}) \mathbf{d}^T \cdot \mathbf{x} \right\} - \mathbf{p}^T \cdot \ell \right] > 0$$

$$\phi \cdot \mathbf{SMP}^T \cdot \mathbf{r}' > \left[\left\{ \mathbf{p}^T \cdot \ell' + \beta \frac{(p_{17} + p_{18})}{2} (r_{17} + r_{18}) \mathbf{d}^T \cdot \mathbf{x} \right\} - \mathbf{p}^T \cdot \ell \right]$$

$$\therefore \phi > \left[\left\{ \mathbf{p}^T \cdot \ell' + \beta \frac{(p_{17} + p_{18})}{2} (r_{17} + r_{18}) \mathbf{d}^T \cdot \mathbf{x} \right\} - \mathbf{p}^T \cdot \ell \right] \times \frac{1}{\mathbf{SMP}^T \cdot \mathbf{r}'}$$

Therefore, only when the proportion to SMP for a residential participant (ϕ) is greater than the ratio of the cost differential (ΔC) over the benefit differential (ΔB), the residential client will participate in the DR program and it is sustainable. If the slop (θ) of the line connecting the origin and the point (x coordinate of the benefit differential and y coordinate of the cost differential) is greater than ϕ , there is no incentive for the residential client to participate in the DR program.

$$\begin{cases} \text{If, } \phi > \theta & \Rightarrow \text{DR Participation,} \\ \text{If, } \phi < \theta & \Rightarrow \text{No DR Participation,} \\ \text{If, } \phi = \theta & \Rightarrow \text{No Difference (indifferent).} \end{cases}$$

where,

$$\begin{cases} \theta & : \text{ ratio of the cost differential } (\Delta C) \text{ over the benefit differential } (\Delta B) \text{ between} \\ & \text{two cases, DR participation and no DR participation (status quo),} \\ & \frac{\Delta(C_1 - C_0)}{\Delta(B_1 - B_0)} = \frac{\Delta C}{\Delta B}. \end{cases}$$

We will do the Decision-making Analysis based on CBA in the 'reference scenario' under the following assumptions:

Box 4.1: Assumptions of 'Reference Scenario' (South Korean DRTM)

1. Required flexibility level:
 - 40%, once this level is decided then the required load reduction, r will be given
2. CBL estimation method:
 - $CBL^{WMA} + SAA$
3. Tariff scheme:
 - uniform tariff scheme both for No DR participation and DR participation,
 - 0.124 Korean Won, ₩/Wh, $\mathbf{p}^u = c = 0.124$, $t \in T = \{1, 2, \dots, 24\}$
4. Inconvenience costs:
 - linear model for inconvenience cost function in terms of the time distance
 - $\beta = 0.5$
5. SMP:
 - SMPs of DR event day (2016-08-12)



The benefits for No DR participation and DR participation are easily calculated.

$$B_0 = 0, B_1 = 17.34, \therefore \Delta B = B_1 - B_0 = 17.34$$

Moreover, The total costs without the DR event have nothing to do with the decision variable, \mathbf{x} , therefore, it is easily calculated, too. That is, $C_0 = 1991.71$.

For the optimization of the total costs, we need to find the decision variables (solution), \mathbf{x} , that minimize the total costs.

$$C_1(\mathbf{x}; \mathbf{p}, \ell') = \underbrace{\mathbf{p}^T \cdot (\ell - \mathbf{r})}_{\text{scalar}} + \underbrace{(r_{17} + r_{18}) \left\{ \mathbf{p}^T + \beta \frac{(p_{17} + p_{18})}{2} \mathbf{d}^T \right\}}_{\text{optimization: } \min_{\mathbf{x}} \text{ Cost}} \cdot \mathbf{x}$$

The first part of the total costs is a scalar value, and it is also easily calculated, which is 1963.62.

Therefore, the **objective function** of the **optimization (linear programming)** will be:

$$\min f(\mathbf{x}) = \min \underbrace{\left\{ \mathbf{p}^T + \beta \frac{(p_{17} + p_{18})}{2} \mathbf{d}^T \right\}}_{\text{coefficient row vector}} \cdot \mathbf{x} \quad (4.26)$$

and, the **constraint equations and inequalities** of the **optimization (linear programming)** are the following.

subject to the constraints,

$$\begin{cases}
 1 \cdot x_1 + 1 \cdot x_2 + \dots + 1 \cdot x_{17} + 1 \cdot x_{18} + \dots 1 \cdot x_{24} = 1 \\
 1 \cdot x_1 + 0 \cdot x_2 + \dots + 0 \cdot x_{17} + 0 \cdot x_{18} + \dots 0 \cdot x_{24} \leq \frac{\text{Cap}_1}{(r_{17}+r_{18})} \cdot \ell_1 \\
 2 \cdot 0 \cdot x_1 + 1 \cdot x_2 + \dots + 0 \cdot x_{17} + 0 \cdot x_{18} + \dots 0 \cdot x_{24} \leq \frac{\text{Cap}_2}{(r_{17}+r_{18})} \cdot \ell_2 \\
 \vdots \\
 \vdots \\
 17 \cdot 0 \cdot x_1 + 0 \cdot x_2 + \dots + 1 \cdot x_{17} + 0 \cdot x_{18} + \dots 0 \cdot x_{24} = 0 \\
 18 \cdot 0 \cdot x_1 + 0 \cdot x_2 + \dots + 0 \cdot x_{17} + 1 \cdot x_{18} + \dots 0 \cdot x_{24} = 0 \\
 \vdots \\
 \vdots \\
 24 \cdot 0 \cdot x_1 + 0 \cdot x_2 + \dots + 0 \cdot x_{17} + 0 \cdot x_{18} + \dots 1 \cdot x_{24} \leq \frac{\text{Cap}_{24}}{(r_{17}+r_{18})} \cdot \ell_{24}
 \end{cases} \tag{4.27}$$

I solved this linear programming relying on the R Package called 'lpSolve' (Berkelaar and others, 2015) which means 'linear programming solve'. In terms of the stochastic feature of this modeling, that is the variable 'Cap' in the above constraint equations and inequalities, I have used the command `set.seed()` for the reproducible research result and reconfirm the numerical result again.

After solving this linear programming, the solution, the decision variable **x** which minimize the cost function, is:

$$\mathbf{x}^T = \begin{matrix} 1 & \dots & 16 & \dots & 19 & \dots & 24 \\ \left(0 & \dots & 0.678 & 0 & 0.322 & \dots & 0 \right) \end{matrix}$$

The following Figure 4.5 represents the actualized loads with the solution for the optimization (linear programming) and the loads without DR participation.

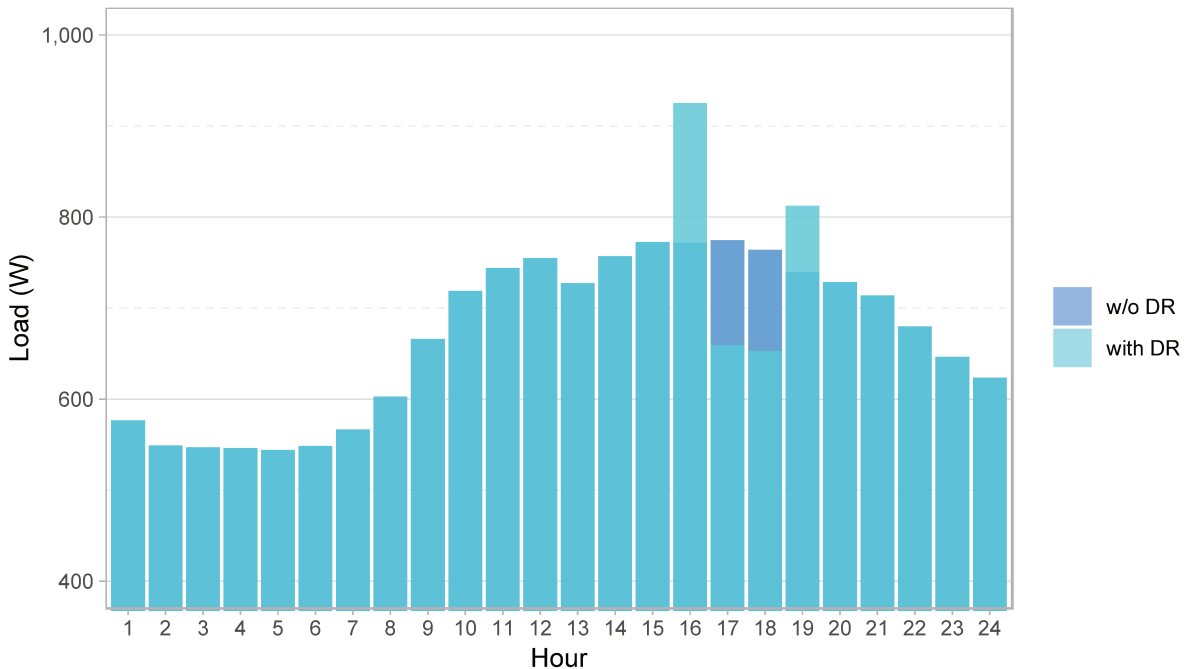


Figure 4.5: Actualized Load Comparison between without DR and with DR Participation (Wh, South Korean DRTM)

With this solution, the value of the minimized cost function is:

$$\begin{aligned}
 & \left\{ \mathbf{p}^T + \beta \frac{(p_{17} + p_{18})}{2} \mathbf{d}^T \right\} \cdot \mathbf{x} = 0.186 \\
 (r_{17} + r_{18}) & \left\{ \mathbf{p}^T + \beta \frac{(p_{17} + p_{18})}{2} \mathbf{d}^T \right\} \cdot \mathbf{x} = 42.14 \\
 \underbrace{\mathbf{p}^T \cdot (\boldsymbol{\ell} - \mathbf{r})}_{1963.62} + & \underbrace{(r_{17} + r_{18}) \left\{ \mathbf{p}^T + \beta \frac{(p_{17} + p_{18})}{2} \mathbf{d}^T \right\} \cdot \mathbf{x}}_{42.14} = 2005.76
 \end{aligned}$$

Therefore, $\Delta C = C_1 - C_0 = 2005.76 - 1991.71 = 14.05$, and the differential Cost-Benefit ratio is $\theta = \frac{\Delta C}{\Delta B} = \frac{14.05}{17.34} = 0.810$

Interpreting this θ , the differential Cost-Benefit ratio, under this scenario (a series of assumptions), only when ϕ is greater than or equal to this $\theta = 0.810$, this DR program is attractive to this residential client and the DR program is sustainable. In other words, if ϕ value is greater than 0.810, it is better to participate in this DR program than no status quo in terms of the profit optimization (cost minimization). Figure 4.6 shows that when ϕ is equal to 1, the red point, which represents the differential Cost-Benefit ratio, is in the sustainable area (gray area under the ϕ line, $y = 1 \cdot x$) in the Cost-Benefit plane.^[9]

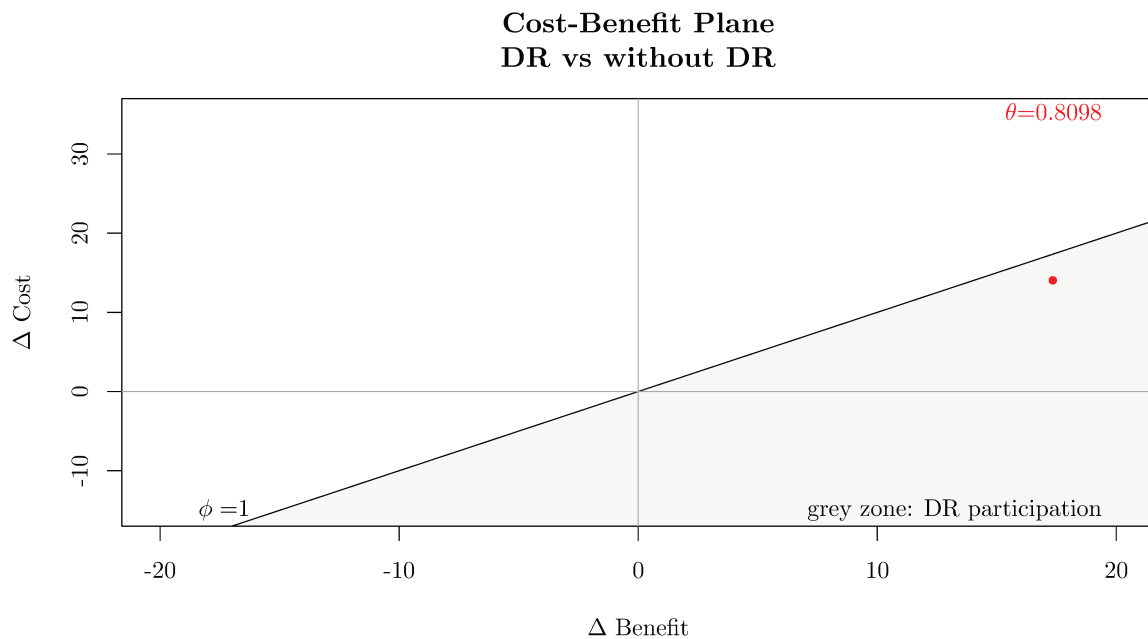


Figure 4.6: Cost-Benefit Plane: DR vs. without DR

^[9] For this 'Cost-Benefit Plane', I utilized with some modification the R Package 'BCEA' created by Baio, Berardi, & Heath (2017; 2018)—BCEA stands for 'Bayesian Cost Effectiveness Analysis'.

4.4 CBA on the French NEBEF Mechanism

In the French NEBEF mechanism, there are two types of DR: 1. load shedding ('l'Effacement de Consommation') and 2. load shifting ('le Report de Consommation'). It is the difference between South Korea and France that in South Korean DR mechanism two types of DR are not clearly divided as long as the DR participants could reduce their electricity consumption at the peak period (required DR event time). The DR system operator does not care whether the participants purely reduce their loads or they shift their load to the later other time slots. Instead, the Demand Resource Trading Market of South Korea categorizes two types of trade: 'economic' DR resources and 'reliability' DR resources. However, in the NEBEF mechanism, RTE makes two types of DR distinct.^[10] Therefore, in this section, I will also make a distinction between them and will set up two models with small modifications for them.

While for the enrolled reliability DR resources the DR system operator makes a request (or order via LAs) to reduce the DR participants' loads during the DR event time in South Korean DR mechanism, in the NEBEF mechanism, whatever it is load shedding or load shifting, there is no this kind of request (or order, call) to LAs—which means there is no reliability DR resource trading in the NEBEF mechanism, only for the economic DR resources. It seems that LAs first declare their DR resources (capacity) to the DR system operator and get the certificates, and in the end, bid at the wholesale market. It means that LAs can calculate themselves and then decide how much and when they will provide load shedding or load shifting. Because the amount of load shedding or load shifting is up to LAs, it is very arbitrary. For the systematic analysis, I will go further in line with the process applied to the South Korean case in terms of the amount of load shedding or load shifting.

The following Figure 4.7 and Table 4.7 are used to calculate 'MinBase', 'Maximum Reducible Capacity', and 40%, 30%, 20% of it (Fig. 4.8 below and Tab. A.17 in Appendix A: Supplementary Figures & Tables). Here, in this French case, the terms 'Required Reduction Level' and 'Required Load Reduction' have changed into 'Target Reduction Level' and 'Target Load Redudction' because LAs can choose and then declare it to RTE themselves.

^[10] According to the distinction in South Korea, we can categorize the two types of the French NEBEF mechanism as economic resources and the economic DR program. As we have seen that in Chapter 2, Section 2.4, in South Korea, we do not have a CRM (Capacity Market), therefore, kind of capacity resources participate in the South Korean DR program as reliability resources. In contrast, in France, there is the CRM, and other markets are all open for DR resources, there is no need to include this reliability resource in the NEBEF mechanism.

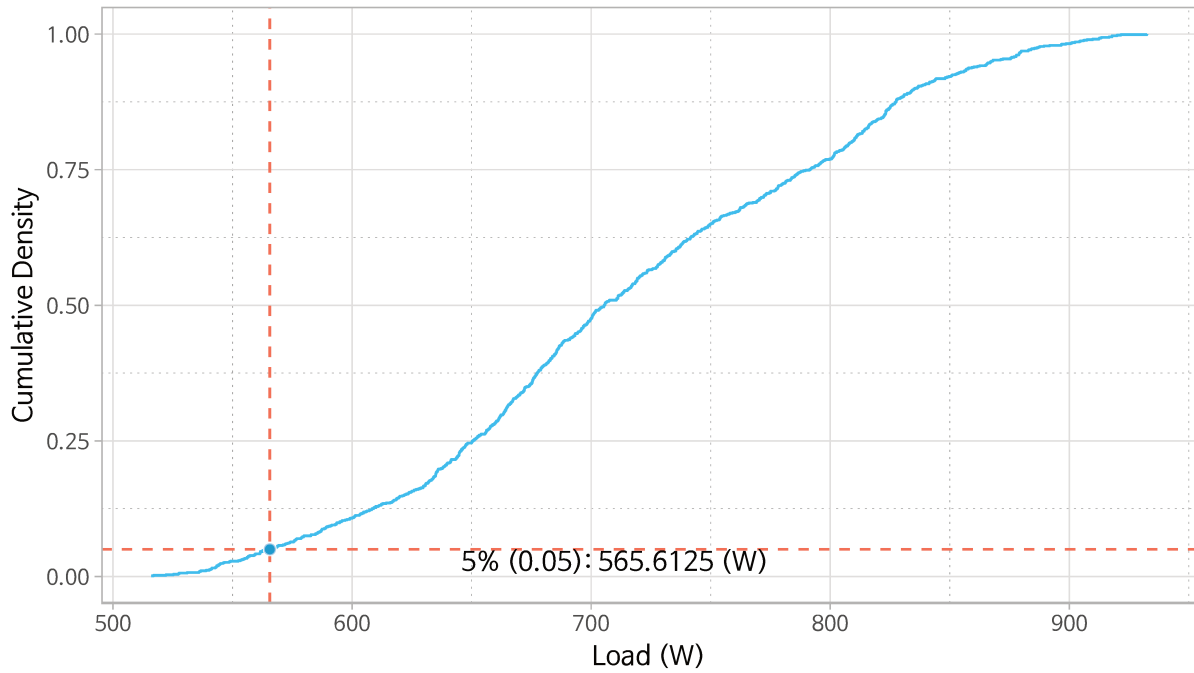


Figure 4.7: Cumulative Density Function of the Maximum Reference Days (20 days prior to Jan. 18, 2016)

Source: The original load data before rescaling, RTE's PORTAIL CLIENTS, "Historique des consommations journalières en puissance". [On-line], Available: https://clients.rte-france.com/lang/fr/clients_traders_fournisseurs/vie/vie_stats_conso_inst.jsp

Table 4.7: The Percentiles of the Cumulative Density Function of the Maximum Reference Days (W)

0%	5%	25%	50%	75%	95%	100%
516	566	656	706	791	867	932

Source: The original load data before rescaling, RTE's PORTAIL CLIENTS, "Historique des consommations journalières en puissance". [On-line], Available: https://clients.rte-france.com/lang/fr/clients_traders_fournisseurs/vie/vie_stats_conso_inst.jsp

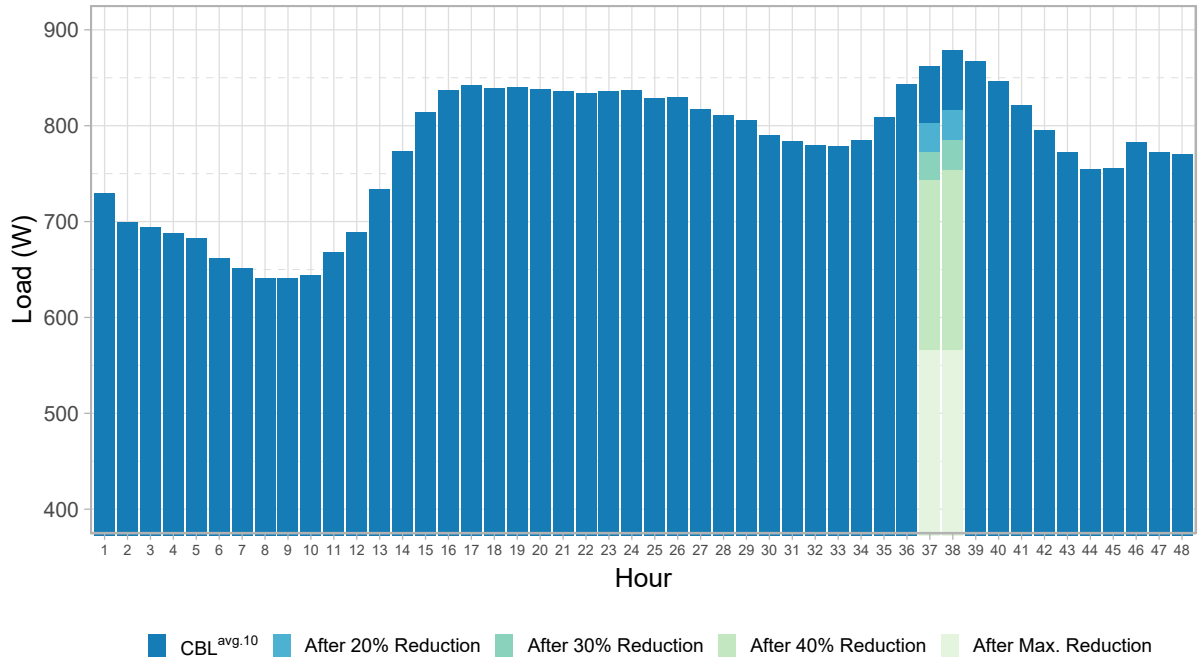


Figure 4.8: The Remained Loads according to the Target Load Reduction Level (20%, 30%, 40%, Max, and CBL) (W)

Comparison to South Korean Case: Fig. 4.2

4.4.1 A Model for the Case of Load Shedding

The model remains almost the same as the model for the South Korean DR mechanism and its CBA. However, some specific elements, for example, half-hourly data, need modifications to represent the characteristics of the NEBEF mechanism and the distinction between load shedding and load shifting in the NEBEF mechanism.

In the following equation, we can notice that there is no \mathbf{x} variable, which represents the weights or coefficients of the load shifting, in the cost part. Therefore, we can regard the following model as the original model with zero \mathbf{x} variable.

$$\begin{aligned} \max_{\mathbf{r}} \Pi(\mathbf{r}; \phi, \mathbf{r}', \mathbf{SMP}, \mathbf{v}, \beta, \mathbf{Coef}^{\text{INC}}) &= B(\phi, \mathbf{r}', \mathbf{SMP}, \mathbf{v}) - C(\mathbf{r}; \beta, \mathbf{Coef}^{\text{INC}}) \\ &= f_o(r_{37}, r_{38}; \phi, r'_{37}, r'_{38}, \mathbf{SMP}_{37}, \mathbf{SMP}_{38}, v_{37}, v_{38}, \beta, \mathbf{Coef}_{37}^{\text{INC}}, \mathbf{Coef}_{38}^{\text{INC}}) \end{aligned} \quad (4.28)$$

The target load reductions are non-negative, $r_t \in \mathbb{R}_+$, for the DR event times, $t = 37$ and $t = 38$, and '0'

(zero) for the other time slots.

$$\mathbf{r} = r_t = \begin{pmatrix} r_1 \\ \vdots \\ r_{36} \\ r_{37} \\ r_{38} \\ r_{39} \\ \vdots \\ r_{48} \end{pmatrix} = \begin{pmatrix} 0 \\ \vdots \\ 0 \\ r_{37} \\ r_{38} \\ 0 \\ \vdots \\ 0 \end{pmatrix} \quad (4.29)$$

where,

$$\left\{ \begin{array}{l} \mathbf{r} : \text{ a column vector consisting of the target load reductions for each time slot,} \\ \text{ especially, for the DR event times,} \\ r_{37} \geq 0, r_{38} \geq 0, r_1 = r_2 = \dots = r_{36} = r_{39} = \dots = r_{48} = 0. \end{array} \right.$$

For example, we can define \mathbf{r}^{20} , \mathbf{r}^{30} , \mathbf{r}^{40} for the target load reduction vector when the target flexibility is 20%, 30%, and 40%, respectively (Fig. 4.8 and Tab. A.17).

$$\begin{array}{ccc} 20\% & 30\% & 40\% \\ \mathbf{r}^{20} = \begin{pmatrix} 0 \\ \vdots \\ 0 \\ 59.20 \\ 62.55 \\ 0 \\ \vdots \\ 0 \end{pmatrix}, \mathbf{r}^{30} = \begin{pmatrix} 0 \\ \vdots \\ 0 \\ 88.80 \\ 93.83 \\ 0 \\ \vdots \\ 0 \end{pmatrix}, \mathbf{r}^{40} = \begin{pmatrix} 0 \\ \vdots \\ 0 \\ 118.40 \\ 125.10 \\ 0 \\ \vdots \\ 0 \end{pmatrix} \end{array}$$

The actually consumed loads without the DR event, which means '0' (zero) reduction $r_{37} = 0$ and $r_{38} = 0$ for $t = 37$ and $t = 38$:

$$\boldsymbol{\ell} = \ell_t = \begin{pmatrix} \ell_1 \\ \ell_2 \\ \vdots \\ \ell_{37} \\ \ell_{38} \\ \vdots \\ \ell_{48} \end{pmatrix} \quad (4.30)$$

where,

$$\left\{ \begin{array}{l} \boldsymbol{\ell} : \text{ a column vector consisting of the actually consumed loads for each time slot,} \\ t \in T = \{1, 2, \dots, 48\}. \end{array} \right.$$

This actually consumed loads will decrease when there is a DR event (in this case, load shedding), therefore there will be load reductions for $t = 37$ and $t = 38$, and here we assume that there is no increase for other time slots (no load shifting from $t = 37$ and $t = 38$). It means all elements of the vector \mathbf{x} are 'zero (0)' in the Equation 4.10 because the vector \mathbf{x} represent the proportion to the entire load reduction to shift to other time slots.

$$\boldsymbol{\ell}' = \boldsymbol{\ell}'_t = \begin{pmatrix} \ell'_1 \\ \ell'_2 \\ \vdots \\ \ell'_{37} \\ \ell'_{38} \\ \vdots \\ \ell'_{48} \end{pmatrix} = \boldsymbol{\ell} - \mathbf{r} = \begin{pmatrix} \ell_1 \\ \vdots \\ \ell_{36} \\ \ell_{37} \\ \ell_{38} \\ \ell_{39} \\ \vdots \\ \ell_{48} \end{pmatrix} - \begin{pmatrix} 0 \\ \vdots \\ 0 \\ r_{37} \\ r_{38} \\ 0 \\ \vdots \\ 0 \end{pmatrix} \quad (4.31)$$

Let us define a column vector of \mathbf{CBL}' in which all the elements are '0' (zero) except 37th and 38th elements, and those are CBL_{37} and CBL_{38} , respectively,

$$\mathbf{CBL}' = \begin{matrix} 1 \\ 2 \\ \vdots \\ 37 \\ 38 \\ \vdots \\ 48 \end{matrix} \begin{pmatrix} 0 \\ 0 \\ \vdots \\ CBL_{37} \\ CBL_{38} \\ \vdots \\ 0 \end{pmatrix} \quad (4.32)$$

and a column vector of $\boldsymbol{\ell}''$ (double prime of $\boldsymbol{\ell}$) in which all the elements are '0' (zero) except 37th and 38th elements, and those are ℓ'_{37} and ℓ'_{38} , respectively.

$$\boldsymbol{\ell}'' = \begin{pmatrix} 0 \\ 0 \\ \vdots \\ \ell'_{37} \\ \ell'_{38} \\ \vdots \\ 0 \end{pmatrix} = \begin{pmatrix} 0 \\ 0 \\ \vdots \\ \ell_{37} \\ \ell_{38} \\ \vdots \\ 0 \end{pmatrix} - \begin{pmatrix} 0 \\ 0 \\ \vdots \\ r_{37} \\ r_{38} \\ \vdots \\ 0 \end{pmatrix} \quad (4.33)$$

Note that the target load reduction \mathbf{r} and actualized load reduction \mathbf{r}' are different. For the target load reduction \mathbf{r} , the residential participant will reduce this amount from the original loads (ℓ_{37} , ℓ_{38}). Then, the

actualized load reduction \mathbf{r}' can be calculated:

$$\mathbf{r}' = \mathbf{CBL}' - \boldsymbol{\ell}'' = \begin{pmatrix} 0 \\ 0 \\ \vdots \\ \text{CBL}_{37} \\ \text{CBL}_{38} \\ \vdots \\ 0 \end{pmatrix} - \begin{pmatrix} 0 \\ 0 \\ \vdots \\ \ell'_{37} \\ \ell'_{38} \\ \vdots \\ 0 \end{pmatrix} = \begin{pmatrix} 0 \\ 0 \\ \vdots \\ r'_{37} \\ r'_{38} \\ \vdots \\ 0 \end{pmatrix} \quad (4.34)$$

where,

$$\left\{ \begin{array}{l} \boldsymbol{\ell}' : \text{ a column vector consisting of the actually consumed loads with the DR event} \\ \text{ for each time slot, } t \in T = \{1, 2, \dots, 48\}. \end{array} \right.$$

For the actualized load reduction the LA will be remunerated at the level of SMP in the wholesale market (EPEX) and the LA should transfer the fixed amount (\mathbf{v}) to the electricity supplier with which the residential participant made the contract of the electricity consumption—this transfer is ‘un versement de l’opérateur d’effacement aux fournisseurs d’électricité des sites de soutirage concernés’.^[11] This fixed amount is different depending on whether it is ‘les Sites de Soutirage Profilés’ or ‘les Sites de Soutirage Télérelevés’, the time of the day (‘heures Basses’ and ‘heures Hautes’), a day (weekdays and weekends), a quarter in a year, and the tariff option.

At this stage I am going to consider the ‘Versement’ (transfer) for ‘les Sites de Soutirage Profilés en option tarifaire Base (1)’ which is 43.58 €/MWh^[12] both for ‘heures Basses’ and ‘heures Hautes’ even though this research is focusing on the residential participants equipped with the AMI (‘les Sites de Soutirage Télérelevés’). In the SA (Section 4.5), I am going to verify the impact of the change in the level of ‘Versement’ (\mathbf{v}).

$$\mathbf{v} = \begin{matrix} t & v_t \\ 1 & \begin{pmatrix} 43.58 \\ 43.58 \\ \vdots \\ 43.58 \end{pmatrix} \\ 2 & \\ \vdots & \\ 48 & \end{matrix} \quad (4.35)$$

After this transfer to the electricity supplier, the remaining remuneration will be divided between the LA and the residential participant.^[13] For the proportion (ϕ) between the LA and the residential participant, let us assume ‘1’ as a default value for ϕ in the ‘reference scenario’ which means that all the remuneration will be

^[11] RTE (2018a, pp. 91–103), 9. Versement dû aux fournisseurs des sites effacés; RTE, 2018, “Les montants du versement du mécanisme NEBEF”. [On-line], Available: https://clients.rte-france.com/lang/fr/clients_traders_fournisseurs/services_clients/dispositif_nebef_montant.jsp

^[12] This is equivalent to the supply (provision) costs (‘le coût d’approvisionnement en énergie’) and it is defined in the last report on the regulatory tariff of the electricity sold published by the CRE. Please, refer to the following document: CRE, (2018), Délibération de la Commission de régulation de l’énergie du 12 juillet 2018 portant proposition des tarifs réglementés de vente d’électricité, [On-line], Available: <https://www.cre.fr/content/download/19519/234917>

^[13] Therefore the accessible remuneration level (net remuneration) for industrial participants is given as the following (ADEME, E-CUBE Strategy Consultants, & CEREN, 2017, pp. 29–30):
(Prix de marché [€/MWh] – Montant du versement [€/MWh] – Coût d’activation) × Volumes effacés [MWh]

paid for the residential participant and there is no gain divided for the LA. Therefore, the net remuneration for the residential participant will be the following (Eq. 4.36):

$$\begin{aligned}
 B(\phi, \mathbf{SMP}, \mathbf{v}, \mathbf{r}') &= \phi(\mathbf{SMP} - \mathbf{v})^T \cdot \mathbf{r}' \\
 &= \phi \left(\begin{array}{cccc} \mathbf{SMP}_1 - v_1 & \mathbf{SMP}_2 - v_2 & \dots & \mathbf{SMP}_{48} - v_{48} \end{array} \right) \begin{pmatrix} 0 \\ 0 \\ \vdots \\ r'_{37} \\ r'_{38} \\ \vdots \\ 0 \end{pmatrix} \quad (4.36)
 \end{aligned}$$

where,

$$\left\{ \begin{array}{l} \phi : \text{the proportion to } (\mathbf{SMP} - \mathbf{v}) \text{ for a residential participant, therefore, the proportion to } (\mathbf{SMP} - \mathbf{v}) \text{ for a load aggregator is } (1-\phi), \\ 0 \leq \phi \leq 1 \\ \mathbf{SMP} : \text{a vector of SMP,} \\ \mathbf{v} : \text{a vector of transfer ('versement') to the electricity supplier.} \end{array} \right.$$

In the following Fig 4.9,^[14] the gradation color bar from blue to yellow means the average SMP in a month and the dashed green line throughout the entire year means the annual average SMP, that is 36.99 EUR(€)/MWh in 2016—34.88 EUR(€)/MWh in 2014 and 38.71 EUR(€)/MWh in 2015. It shows the high variance of SMP in 2016, especially during the fourth quarter, compared to that of 2014 (Fig. A.29) and 2015 (Fig. A.30), considering the standard deviation (**Std.Dev**), the difference between minimum (**Min**) and maximum (**Max**) in Table 4.8 and the outliers in Figure 4.10).

^[14] You can find Figure A.29 and A.30 which represent the time series SMP data in France, 2014 and 2015 in Appendix A: Supplementary Figures & Tables.

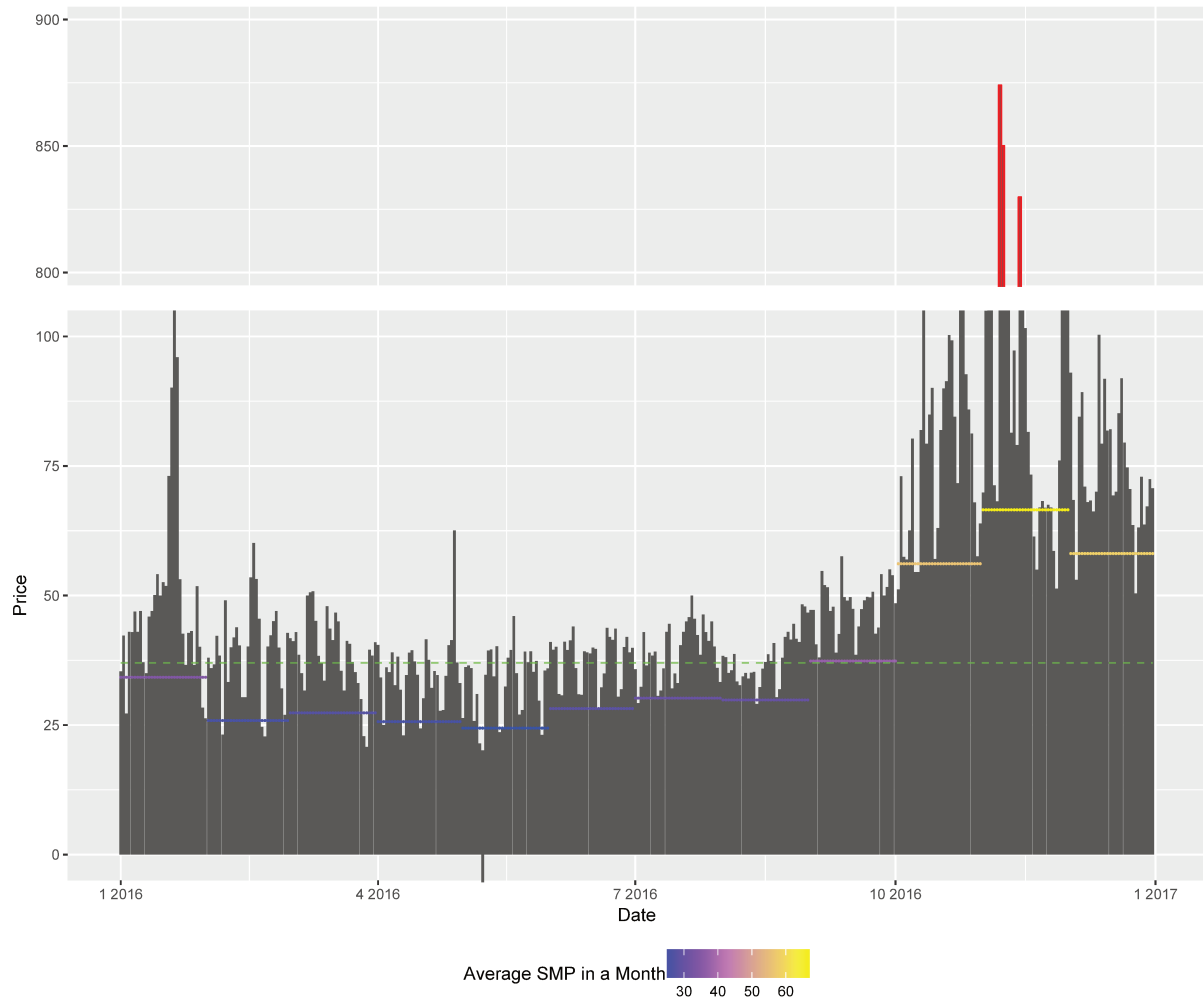


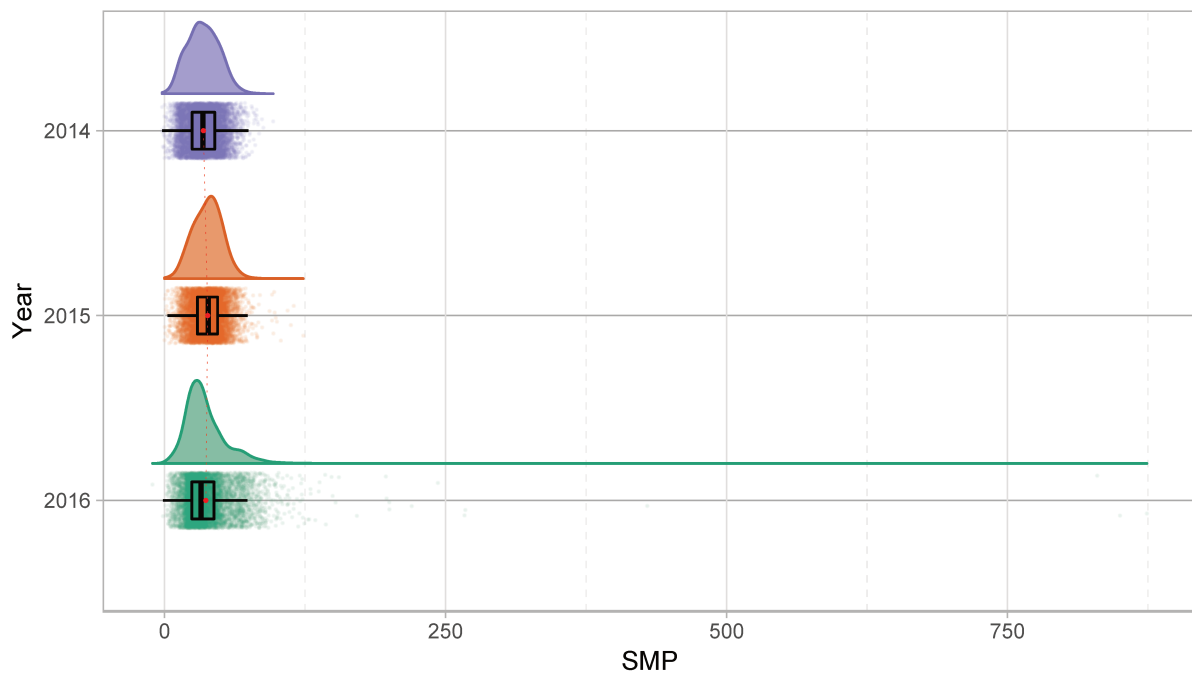
Figure 4.9: SMP, France in 2016 (EUR(€)/MWh)

Source: "Prices - EPEX Spot Market Auction - France", EPEX, [On-line], Available: http://www.epexspot.com/fr/donnees_de_marche

Comparison to South Korea: Fig. 4.3

Table 4.8: Descriptive Statistics of SMP in 2014, 2015, 2016 (France)

	2014	2015	2016
Mean	34.63	38.48	36.75
Std.Dev	13.91	12.95	24.44
Min	-2.12	0.02	-10.69
Q1	24.60	29.28	24.30
Median	34.11	39.02	32.44
Q3	44.71	47.20	44.06
Max	96.69	123.46	874.01
MAD	14.81	13.36	13.67
IQR	20.10	17.92	19.75
CV	0.40	0.34	0.67
Skewness	0.19	0.19	14.12
SE.Skewness	0.03	0.03	0.03
Kurtosis	-0.32	0.65	432.69
N.Valid	8759.00	8759.00	8783.00
Pct.Valid	99.99	99.99	99.99

**Figure 4.10:** Raincloud Plots of SMPs in 2014, 2015, 2016 (France, €/MWh)

Credit for *Raincloud Plots*: [Allen et al. \(2018, 2019\)](#)

Focusing on the SMPs for $t = 37$ and $t = 38$, which is the SMP at 7 p.m. (19:00), on Monday, Jan. 18, 2016 in France, it was the following (Tab. 4.9). For the calculation, if we translate it into cts (centimes) €/Wh it is 0.007307 cts €/Wh.

Table 4.9: The SMP for the DR Event (NEBEF) Times (€/MWh)

2016-01-18				
	...	$t = 37$	$t = 38$...
SMP	...	73.07	73.07	...

Source: “Prices - EPEX Spot Market Auction - France”, EPEX, [On-line], Available: http://www.epexspot.com/fr/donnees_de_marche

If there is no DR event and no target reduction, the net benefit will be zero, ‘0’ because $r_t = 0$, where, $t \in T = \{1, 2, \dots, 48\}$.

When it comes to the cost function for the load shedding case of the NEBEF DR event, basically it is the same with the cost function (Eq. 4.15) of the previous model applied to the South Korean case except that the second part, ‘additional inconvenience costs (INC)’ is not derived from the load shifting but from the load shedding itself—in that sense it can be regarded as ‘Participant Value of Lost Service’ (Woolf et al., 2013, pp. v–vi). This additional inconvenience is that due to load shedding we cannot consume the electricity and we cannot fulfill associated activities with this electricity consumption, so it causes some loss of the welfare from the consumer’s perspective—loss of the marginal utility. If it were the industrial sector, these additional inconvenience costs are equivalent to the activation cost of NEBEF. For example, due to this load reduction, the factory should be stopped and restart again later, the factory cannot meet the planned production schedule, and so forth.^[15]

In terms of the retail price of the uniform tariff scheme (\mathbf{p}^u in the Equation 4.16), I could use the price of the tariff scheme ‘Tarif de Base (Bleu)’ for an average power rating^[16]—it was 14.67 cts €/KWh ($\Rightarrow 0.01467$ cts €/Wh).^[17] However, I am going to use the average retail price for electricity because I am focusing on an average household using the rescaled load profile. The following Table 4.10 shows the unit average retail price for residential usage in 2010, 2013, 2014, 2015, and 2016.

Table 4.10: The Unit Average Retail Price for Residential Usage (Euro, €/MWh)

2010	2013	2014	2015	2016
124.4	146.7	153.5	159.4	164.8

Source: IEA, 2017, *Electricity Information 2017*, IEA, Paris p. IV.8, Table 2d. Electricity prices for households in national currency/MWh.

For the retail price of the ToU tariff scheme (\mathbf{p}^{tou} in the Equation 4.16), at this stage, I am going to use the tariff scheme of ‘Option Heures Creuses’ of EDF in which the price is 16.00 cts €/KWh ($\Rightarrow 0.016$ cts €/Wh) for peak time (‘Heures Pleines’, between 8 a.m. and 8 p.m.) and 11.14 cts €/KWh ($\Rightarrow 0.01114$ cts €/Wh) for

^[15] Of course, if the factory is equipped with back-up generators, and it is running the back-up generators while reducing the electricity consumption from the system, there would be no interruption for the planned production schedule. In this case, the additional inconvenience costs are the operating costs of the back-up generators.

^[16] EDE, 2018, “Tarif Bleu: le tarif réglementé de vente de l’électricité”, [On-line], Available: <https://particulier.edf.fr/fr/accueil/offres/electricite/tarif-bleu.html>

^[17] Applicable from August, 2015 to July, 2016. EDE, 2015, “Grilles tarifaires de l’offre de fourniture d’électricité «Tarif Bleu»”, [On-line], Available: https://particulier.edf.fr/content/dam/2-Actifs/Documents/Offres/Grilles%20des%20tarifs_TB_082015.pdf

off-peak time ('Heures Creuses', between 8 p.m. and 8 a.m.).^[18]


$$\mathbf{p}^{\text{tou}} = \begin{matrix} t & p_t^{\text{tou}} \\ 1 & 0.01114 \\ 2 & 0.01114 \\ \vdots & \vdots \\ 15 & 0.01114 \\ 16 & 0.01114 \\ 17 & 0.01600 \\ 18 & 0.01600 \\ \vdots & \vdots \\ 39 & 0.01600 \\ 40 & 0.01600 \\ 41 & 0.01114 \\ 42 & 0.01114 \\ \vdots & \vdots \\ 48 & 0.01114 \end{matrix} \quad (4.37)$$

Instead of the vector of time distance \mathbf{d} in the Equation 4.22, here I am going to generalize it to represent the coefficient of inconvenience due to load shedding (also, it can be applied to load shifting later). The coefficient vector $\mathbf{Coef}^{\text{INC}}$ can vary depending on each residential participant's different condition, perception on inconvenience for each time slot. Here, let us set this value as '1' for all the time slots, which means for this residential participant the degree of inconvenience due to the load shedding is all the same across the time slots. Later, in the SA section (Section 4.5), I am going to modify this generalized inconvenience vector $\mathbf{Coef}^{\text{INC}}$ in order to represent several different conditions and perceptions on load shedding and load shifting for different participants.

$$\mathbf{Coef}^{\text{INC}} = \mathbf{Coef}_t^{\text{INC}} = \begin{pmatrix} \text{Coef}_1^{\text{INC}} \\ \text{Coef}_2^{\text{INC}} \\ \vdots \\ \text{Coef}_{36}^{\text{INC}} \\ \text{Coef}_{37}^{\text{INC}} \\ \text{Coef}_{38}^{\text{INC}} \\ \text{Coef}_{39}^{\text{INC}} \\ \vdots \\ \text{Coef}_{48}^{\text{INC}} \end{pmatrix} = \begin{pmatrix} 1 \\ 1 \\ \vdots \\ 1 \\ 1 \\ 1 \\ 1 \\ \vdots \\ 1 \end{pmatrix} \quad (4.38)$$

where,

$\left\{ \begin{array}{l} \mathbf{Coef}^{\text{INC}} \\ \end{array} \right.$: a vector of generalized coefficients representing additional inconvenience of load shedding (or load shifting), $t \in T = \{1, 2, \dots, 48\}$.

^[18]  Applicable from August, 2015 to July, 2016. EDE, 2015, "Grilles tarifaires de l'offre de fourniture d'électricité «Tarif Bleu»", [On-line], Available: https://particulier.edf.fr/content/dam/2-Actifs/Documents/Offres/Grilles%20des%20tarifs_TB_082015.pdf

With this generalized inconvenience vector $\mathbf{Coef}^{\mathbf{INC}}$, the formula for INC for load shedding is the following:

$$INC_t = \beta \frac{(p_{37} + p_{38})}{2} \mathbf{Coef}_t^{\mathbf{INC}} \cdot r_t \quad (4.39)$$

$$\mathbf{INC} = \begin{pmatrix} INC_1 \\ INC_2 \\ \vdots \\ INC_{48} \end{pmatrix} = \beta \frac{(p_{37} + p_{38})}{2} \cdot \mathit{diag}(\mathbf{Coef}^{\mathbf{INC}} \otimes \mathbf{r}) \quad (4.40)$$

where,

$$\left\{ \begin{array}{ll} INC_t & : \text{additional inconvenience costs,} \\ & t \in T = \{1, 2, \dots, 48\}, \\ \beta & : \text{the relative ratio of inconvenience to the unit present value of the electricity} \\ & \text{consumption at the DR event time,} \\ \frac{(p_{37} + p_{38})}{2} & : \text{the average retail price for } t = 37 \text{ and } t = 38, \\ \mathbf{Coef}_t^{\mathbf{INC}} & : \text{a generalized inconvenience coefficient for each time slot,} \\ & t \in T = \{1, 2, \dots, 48\}, \\ r_t & : \text{load reduction at the DR event time slot,} \\ & t \in T = \{1, 2, \dots, 48\}, \\ \mathit{diag}(\cdot) & : \text{a column vector consisting of diagonal elements,} \\ \mathbf{Coef}^{\mathbf{INC}} \otimes \mathbf{r} & : \text{outer product of the two vectors.} \end{array} \right.$$

$$\text{Total INC} = \beta \frac{(p_{37} + p_{38})}{2} \mathbf{Coef}^{\mathbf{INC}} \cdot \mathbf{r} \quad (4.41)$$

Likewise, as we have assumed that the default value of $\beta = 0.5$ for the CBA of the South Korean case, let us start with $\beta = 0.5$ and then, in the SA, we are going to modify the value of β representing different participants' perceptions on the value of *willingness-to-accept* (WTA) for the inconvenience to reduce their as usual loads.

In summary, the functions for the total benefits and total costs of the NEBEF DR event (load shedding) are the following:

$$\left\{ \begin{array}{l} B_1(\phi, \mathbf{r}', \mathbf{SMP}, \mathbf{v}) = \phi(\mathbf{SMP} - \mathbf{v})^T \cdot \mathbf{r}' \\ C_1(\mathbf{r}; \mathbf{p}, \ell', \beta, \mathbf{Coef}^{\mathbf{INC}}) = \mathbf{p}^T \cdot \ell' + \beta \frac{(p_{37} + p_{38})}{2} (\mathbf{Coef}^{\mathbf{INC}})^T \cdot \mathbf{r} \end{array} \right.$$

In the case of no NEBEF DR event (load shedding) (status quo):

$$\left\{ \begin{array}{l} B_0(\phi, \mathbf{r}', \mathbf{SMP}, \mathbf{v}) = \phi(\mathbf{SMP} - \mathbf{v})^T \cdot \mathbf{r}' = 0 \quad \because \mathbf{r}' = 0 \\ C_0(\mathbf{p}, \ell) = \mathbf{p}^T \cdot \ell \end{array} \right.$$

4.4.2 Decision-making Analysis for the Case of Load Shedding Based on CBA

The basic idea of the decision-making analysis for the case of the load shedding NEBEF mechanism based on CBA remains the same except the following inequality conditions which reflect the modification of the model for load shedding.

if $(\mathbf{SMP} - \mathbf{v})^T \cdot \mathbf{r}' > 0$, then θ should be less than ϕ ($\phi > \theta$):

$$\phi > \left[\left\{ \mathbf{p}^T \cdot \boldsymbol{\ell}' + \beta \frac{(p_{37} + p_{38})}{2} (\mathbf{Coef}^{\text{INC}})^T \cdot \mathbf{r} \right\} - \mathbf{p}^T \cdot \boldsymbol{\ell} \right] \times \frac{1}{(\mathbf{SMP} - \mathbf{v})^T \cdot \mathbf{r}'}$$

if $(\mathbf{SMP} - \mathbf{v})^T \cdot \mathbf{r}' < 0$, then θ should be greater than ϕ ($\phi < \theta$):

$$\phi < \left[\left\{ \mathbf{p}^T \cdot \boldsymbol{\ell}' + \beta \frac{(p_{37} + p_{38})}{2} (\mathbf{Coef}^{\text{INC}})^T \cdot \mathbf{r} \right\} - \mathbf{p}^T \cdot \boldsymbol{\ell} \right] \times \frac{1}{(\mathbf{SMP} - \mathbf{v})^T \cdot \mathbf{r}'}$$

We will do the Decision-making Analysis based on CBA in the 'reference scenario' under the following assumptions:

Box 4.2: Assumptions of 'Reference Scenario' (Load Shedding, French NEBEF)

1. Target flexibility level:
 - 40%, once this level is decided then the required load reduction, \mathbf{r} will be given
2. CBL estimation method:
 - $\text{CBL}^{\text{avg.10}}$
3. Tariff scheme:
 - uniform tariff scheme both for No DR participation and DR participation
 - 0.01648 cts €/Wh, $\mathbf{p}^u = c = 0.01648$, $t \in T = \{1, 2, \dots, 48\}$
4. Inconvenience costs:
 - linear model for inconvenience cost function in terms of the time distance
 - $\beta = 0.5$
5. SMP:
 - SMPs of DR event day (2016-01-18)

↑

The following Figure 4.11 shows the resulting actualized loads with DR participation considering only load shedding, not load shifting.

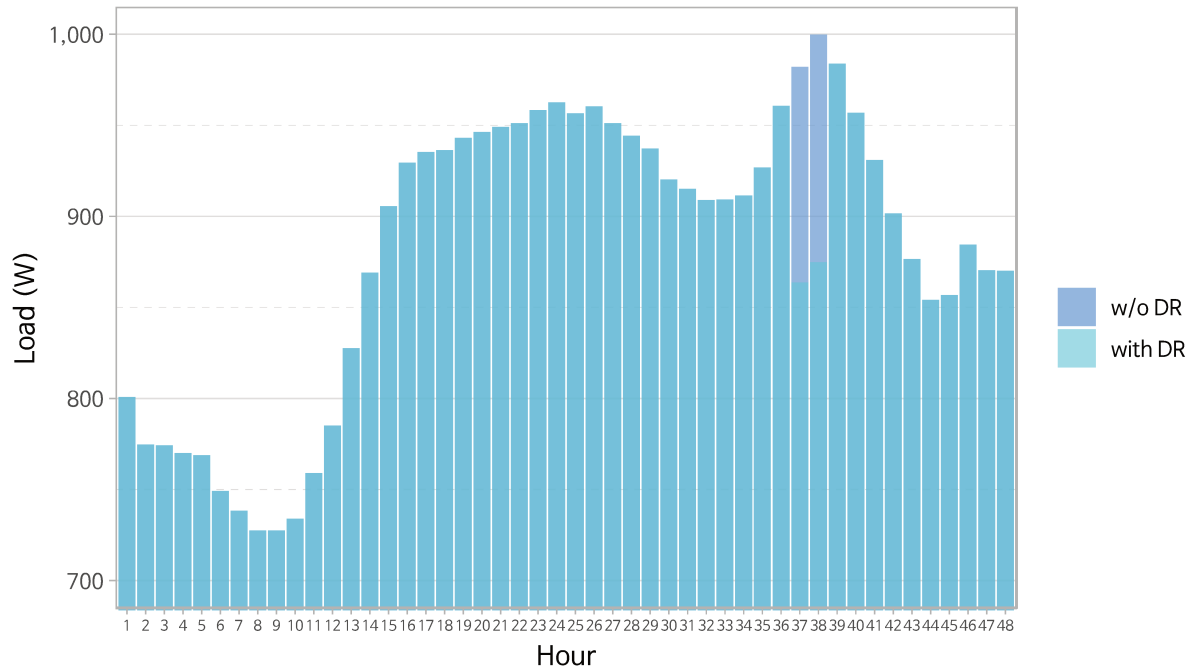


Figure 4.11: Actualized Load Comparison between without DR and with DR Participation in NEBEF Mechanism (W)

In this situation, the differential of benefits is $\Delta B = B_1 - B_0 = 0.01053191$, and the differential of costs is $\Delta C = C_1 - C_0 = -2.008847$. Therefore, the ratio of cost-benefit differential (θ) is $\theta = \frac{\Delta C}{\Delta B} = -190.739$.

In the following Figure 4.12, the red point represents the coordinates of ΔB and ΔC , and θ means the slope of the line which connects the origin with the red point. As can be seen in the Figure, the red point is in the grey zone and the value of θ is less than the value of ϕ . That means the net benefits with the DR participation are greater than the net benefits without the DR participation, and therefore the residential client will decide to participate in it.

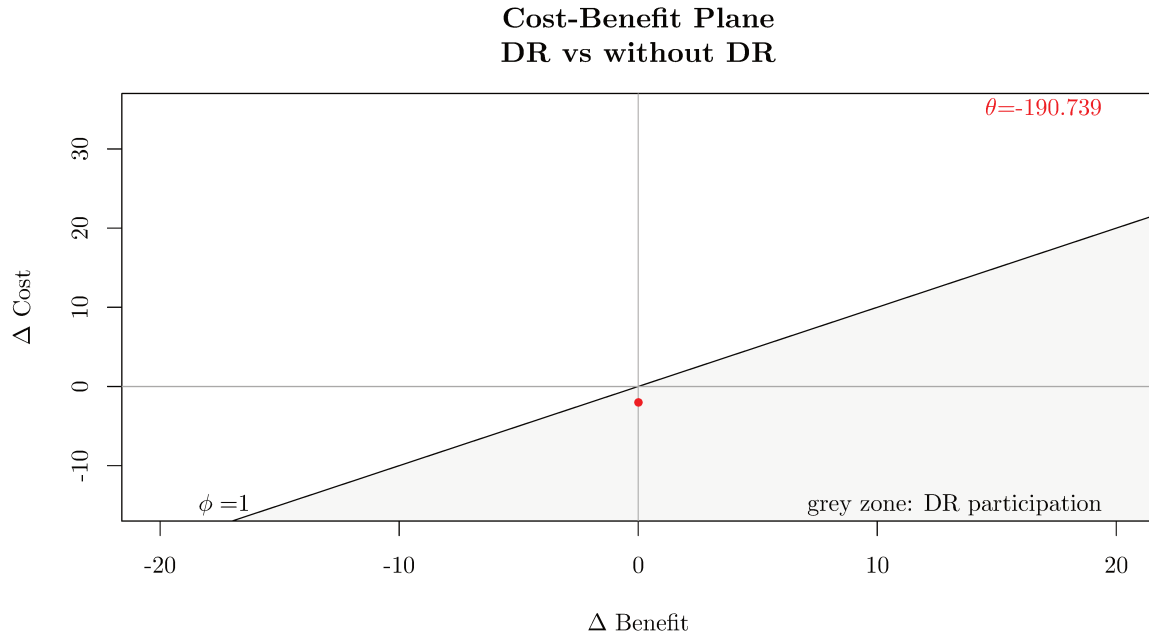


Figure 4.12: Cost-Benefit Plane: DR vs. without DR (NEBEF, Load Shedding)

4.4.3 A Model for the Case of Load Shifting

The model remains almost the same as the model for the load shedding case of the NEBEF mechanism. However, some specific elements need modifications to represent the characteristics of the load shifting in the NEBEF mechanism. In the following equation, we can notice that there is \mathbf{x} variable like Equation 4.5 for the South Korean case, which represents the weights or coefficients of the load shifting, in the cost part.

In the French NEBEF case, load shifting 'le Report de Consommation' literally means the postponement or delay of consumption. Therefore, we have assumed that it is only possible to shift reductions to the later time slots than $t = 37$ and $t = 38$. As a consequence, all the values of \mathbf{x} for time slots from $t = 01$ to $t = 37$ and $t = 38$ are zero (○)^[19] and all the values of \mathbf{x} for time slots from $t = 39$ to $t = 48$ are greater than or equal to zero (○). This is one of the differences between the French NEBEF load shifting case and the Korean DRTM case in which we have assumed that it is also possible to shift reductions to the earlier time slots than the DR event period, $t = 17$ and $t = 18$.

$$\begin{aligned} \max_{\mathbf{r}, \mathbf{x}} \Pi(\mathbf{r}, \mathbf{x}; \phi, \mathbf{r}', \mathbf{SMP}, \beta, \mathbf{p}, \mathbf{Coef}^{\text{INC}}) &= B(\phi, \mathbf{r}', \mathbf{SMP}, \mathbf{v}) - C(\mathbf{r}, \mathbf{x}; \beta, \mathbf{p}, \mathbf{Coef}^{\text{INC}}) \\ &= f_o(r_{37}, r_{38}, x_1, x_2, \dots, x_{48}; \phi, r'_{37}, r'_{38}, \text{SMP}_{37}, \text{SMP}_{38}, v_{37}, v_{38}, p_{37}, p_{38}, \text{Coef}_{37}^{\text{INC}}, \text{Coef}_{38}^{\text{INC}}) \end{aligned} \quad (4.42)$$

^[19] ○ In other words, again, the zero values for \mathbf{x} at the time slots $t = 37$ and $t = 38$ mean there is no partial load shedding, which is, all the required load reduction will be fulfilled and shifted other time slots. Also, the zero values for \mathbf{x} at the time slots between $t = 01$ and $t = 36$ mean there is no load shifting to the time slots before the DR event times because it literally means the postponement of the loads in French NEBEF mechanism.

$$\mathbf{x} = x_t = \begin{pmatrix} x_1 \\ \vdots \\ x_{37} \\ x_{38} \\ x_{39} \\ \vdots \\ x_{48} \end{pmatrix} = \begin{pmatrix} 0 \\ \vdots \\ 0 \\ 0 \\ x_{39} \\ \vdots \\ x_{48} \end{pmatrix} \quad (4.43)$$

where,

$\left\{ \begin{array}{l} \mathbf{x} : \text{ a column vector consisting of the proportions to the total target load reduction that will be shifted to other time slots, } t \in T = \{1, 2, \dots, 48\}, \text{ except from } t = 01 \text{ to } t = 37 \text{ and } t = 38. \end{array} \right.$

subject to the constraints,

$$\left\{ \begin{array}{l} \sum_{t=1}^{48} x_t = 1 \\ x_1, x_2, \dots, x_{37}, x_{38} = 0 \\ x_{39}, \dots, x_{48} \geq 0 \\ x_{39}, \dots, x_{48} \leq \frac{\text{Cap}_t}{(r_{37} + r_{38})} \cdot \ell_t \end{array} \right. \quad (4.44)$$

where,

$\left\{ \begin{array}{l} \text{Cap} : \text{ a vector of the capacity factor, which represents the potential capacity to accept some part of the total required load reduction. In order to represent 'stochastic' capacity, individual property, daily conditions, it is 'random number' (pseudo-random number) from uniform distribution between '0' and required flexibility level (RFL),} \\ \mathbf{Cap} \sim U(0, \text{RFL}) \\ 0 \leq \text{Cap}_t \leq \text{RFL} \\ t \in T = \{1, 2, \dots, 48\} \\ \text{RFL} : \text{ required flexibility level, such as, 0.2 (20\%), 0.3 (30\%), 0.4 (40\%), or 1 (max).} \end{array} \right.$

The target load reductions are the same with the load shedding case of the NEBEF mechanisms (Eq. 4.29) as well as the actually consumed loads without the DR event. However, in this load shifting case, the actually consumed loads with DR is different from those of the load shedding case because we need to consider the

load shifting and the variable \mathbf{x} . Moreover, the following ℓ' is used for ℓ'' , and in turn, \mathbf{r}' .

$$\begin{aligned} \ell' = \ell'_t &= \begin{pmatrix} \ell'_1 \\ \vdots \\ \ell'_{37} \\ \ell'_{38} \\ \ell'_{39} \\ \ell'_{40} \\ \vdots \\ \ell'_{48} \end{pmatrix} = \ell - \mathbf{r} + (r_{37} + r_{38})\mathbf{x} \\ &= \begin{pmatrix} \ell_1 \\ \vdots \\ \ell_{37} \\ \ell_{38} \\ \ell_{39} \\ \vdots \\ \ell_{48} \end{pmatrix} - \begin{pmatrix} 0 \\ \vdots \\ r_{37} \\ r_{38} \\ 0 \\ \vdots \\ 0 \end{pmatrix} + (r_{37} + r_{38}) \begin{pmatrix} 0 \\ \vdots \\ 0 \\ 0 \\ x_{39} \\ \vdots \\ x_{48} \end{pmatrix} \end{aligned} \quad (4.45)$$

The benefit function remains the same with the load shedding case of the NEBEF mechanism, but the cost function is different, especially for Coef^{INC} . This time Coef^{INC} represents the additional inconvenience of load shifting to the later time slots after the DR event time slots.

$$\text{Coef}^{\text{INC}} = \text{Coef}_t^{\text{INC}} = \begin{pmatrix} \text{Coef}_1^{\text{INC}} \\ \text{Coef}_2^{\text{INC}} \\ \vdots \\ \text{Coef}_{36}^{\text{INC}} \\ \text{Coef}_{37}^{\text{INC}} \\ \text{Coef}_{38}^{\text{INC}} \\ \text{Coef}_{39}^{\text{INC}} \\ \text{Coef}_{40}^{\text{INC}} \\ \vdots \\ \text{Coef}_{48}^{\text{INC}} \end{pmatrix} = \begin{pmatrix} 0 \\ 0 \\ \vdots \\ 0 \\ 0 \\ 0 \\ 1.0 \\ 1.1 \\ \vdots \\ 1.9 \end{pmatrix} \quad (4.46)$$

where,

$\left\{ \text{Coef}^{\text{INC}} \right\}$: a vector of generalized coefficients representing additional inconvenience of load shifting (or load shedding), $t \in T = \{1, 2, \dots, 48\}$.

$$\text{INC}_t = \beta \frac{(p_{37} + p_{38})}{2} \text{Coef}_t^{\text{INC}} (r_{37} + r_{38}) x_t \quad (4.47)$$

$$\text{INC} = \begin{pmatrix} \text{INC}_1 \\ \text{INC}_2 \\ \vdots \\ \text{INC}_{48} \end{pmatrix} = \beta \frac{(p_{37} + p_{38})}{2} (r_{37} + r_{38}) \cdot \text{diag}(\text{Coef}^{\text{INC}} \otimes \mathbf{x}) \quad (4.48)$$

where,

$$\left\{ \begin{array}{ll} \text{INC}_t & : \text{ additional inconvenience costs,} \\ & t \in T = \{1, 2, \dots, 48\}, \\ \beta & : \text{ the relative ratio of inconvenience to the unit present value of the electricity} \\ & \text{ consumption at the DR event time,} \\ \frac{(p_{37}+p_{38})}{2} & : \text{ the average retail price for } t = 37 \text{ and } t = 38, \\ (r_{37} + r_{38}) & : \text{ the total load reduction for } t = 37 \text{ and } t = 38, \text{ and it is the amount to be} \\ & \text{ shifted to other time slots,} \\ \text{Coef}_t^{\text{INC}} & : \text{ a generalized inconvenience coefficient for each time slot,} \\ & t \in T = \{1, 2, \dots, 48\}, \\ x_t & : \text{ proportion to the total load reduction,} \\ & t \in T = \{1, 2, \dots, 48\}, \\ \text{diag}(\cdot) & : \text{ a column vector consisting of diagonal elements,} \\ \text{Coef}^{\text{INC}} \otimes \mathbf{x} & : \text{ outer product of the two vectors.} \end{array} \right.$$

$$\text{Total INC} = \beta \frac{(p_{37} + p_{38})}{2} (r_{37} + r_{38}) (\text{Coef}^{\text{INC}})^{\text{T}} \cdot \mathbf{x}$$

In summary, the functions for the total benefits and total costs of the NEBEF DR event (load shifting) are the following:

$$\left\{ \begin{array}{l} B_1(\phi, \mathbf{r}', \text{SMP}, \mathbf{v}) = \phi (\text{SMP} - \mathbf{v})^{\text{T}} \cdot \mathbf{r}' \\ C_1(\mathbf{r}, \mathbf{x}; \mathbf{p}, \boldsymbol{\ell}', \beta, \text{Coef}^{\text{INC}}) = \mathbf{p}^{\text{T}} \cdot \boldsymbol{\ell}' + \beta \frac{(p_{37}+p_{38})}{2} (r_{37} + r_{38}) (\text{Coef}^{\text{INC}})^{\text{T}} \cdot \mathbf{x} \end{array} \right.$$

In the case of no NEBEF DR event (load shifting) (status quo):

$$\left\{ \begin{array}{l} B_0(\phi, \mathbf{r}', \text{SMP}, \mathbf{v}) = \phi (\text{SMP} - \mathbf{v})^{\text{T}} \cdot \mathbf{r}' = 0 \quad \because \mathbf{r}' = 0 \\ C_0(\mathbf{p}, \boldsymbol{\ell}) = \mathbf{p}^{\text{T}} \cdot \boldsymbol{\ell} \end{array} \right.$$

4.4.4 Decision-making Analysis for the Case of Load Shifting based on CBA

The basic idea of the decision-making analysis for the case of the load shifting NEBEF mechanism based on CBA remains the same with the case of the load shedding NEBEF mechanism except for the following inequality conditions which reflect the modification of the model for load shifting.

if $(\text{SMP} - \mathbf{v})^{\text{T}} \cdot \mathbf{r}' > 0$, then θ should be less than ϕ ($\phi > \theta$):

$$\phi > \left[\left\{ \mathbf{p}^{\text{T}} \cdot \boldsymbol{\ell}' + \beta \frac{(p_{37}+p_{38})}{2} (r_{37} + r_{38}) (\text{Coef}^{\text{INC}})^{\text{T}} \cdot \mathbf{x} \right\} - \mathbf{p}^{\text{T}} \cdot \boldsymbol{\ell} \right] \times \frac{1}{(\text{SMP} - \mathbf{v})^{\text{T}} \cdot \mathbf{r}'}$$

if $(\text{SMP} - \mathbf{v})^{\text{T}} \cdot \mathbf{r}' < 0$, then θ should be greater than ϕ ($\phi < \theta$):

$$\phi < \left[\left\{ \mathbf{p}^{\text{T}} \cdot \boldsymbol{\ell}' + \beta \frac{(p_{37}+p_{38})}{2} (r_{37} + r_{38}) (\text{Coef}^{\text{INC}})^{\text{T}} \cdot \mathbf{x} \right\} - \mathbf{p}^{\text{T}} \cdot \boldsymbol{\ell} \right] \times \frac{1}{(\text{SMP} - \mathbf{v})^{\text{T}} \cdot \mathbf{r}'}$$

We will do the Decision-making Analysis based on CBA in the ‘reference scenario’ under the following assumptions:

Box 4.3: Assumptions of ‘Reference Scenario’ (Load Shifting, French NEBEF)

1. Target flexibility level:
 - 40%, once this level is decided then the required load reduction, r will be given
2. CBL estimation method:
 - $CBL^{avg.10}$
3. Tariff scheme:
 - uniform tariff scheme both for No DR participation and DR participation
 - 0.01648 cts €/Wh, $p^u = c = 0.01648$, $t \in T = \{1, 2, \dots, 48\}$
4. Inconvenience costs:
 - linear model for inconvenience cost function in terms of the time distance
 - $\beta = 0.5$
5. SMP:
 - SMPs of DR event day (2016-01-18)

↑

Like the Korean DTRM, the **objective function** of the **optimization (linear programming)** will be:

$$\min f(\mathbf{x}) = \min \underbrace{\left\{ \mathbf{p}^T + \beta \frac{(p_{37} + p_{38})}{2} (\mathbf{Coef}^{INC})^T \right\}}_{\text{coefficient row vector}} \cdot \mathbf{x} \quad (4.49)$$

and, the **constraint equations and inequalities** of the **optimization (linear programming)** are the following.

subject to the constraints,

$$\left\{ \begin{array}{l} 1 \cdot x_1 + \dots + 1 \cdot x_{37} + 1 \cdot x_{38} + 0 \cdot x_{39} + \dots + 0 \cdot x_{47} + 1 \cdot x_{48} = 1 \\ 1 \cdot x_1 + \dots + 0 \cdot x_{37} + 0 \cdot x_{38} + 0 \cdot x_{39} + \dots + 0 \cdot x_{47} + 0 \cdot x_{48} = 0 \\ \vdots \\ 37 \cdot 0 \cdot x_1 + \dots + 1 \cdot x_{37} + 0 \cdot x_{38} + 0 \cdot x_{39} + \dots + 0 \cdot x_{47} + 0 \cdot x_{48} = 0 \\ 38 \cdot 0 \cdot x_1 + \dots + 0 \cdot x_{37} + 1 \cdot x_{38} + 0 \cdot x_{39} + \dots + 0 \cdot x_{47} + 0 \cdot x_{48} = 0 \\ 39 \cdot 0 \cdot x_1 + \dots + 0 \cdot x_{37} + 0 \cdot x_{38} + 1 \cdot x_{39} + \dots + 0 \cdot x_{47} + 0 \cdot x_{48} \leq \frac{Cap_{39}}{(r_{37}+r_{38})} \cdot l_{39} \\ \vdots \\ 48 \cdot 0 \cdot x_1 + \dots + 0 \cdot x_{37} + 0 \cdot x_{38} + 0 \cdot x_{39} + \dots + 0 \cdot x_{47} + 1 \cdot x_{48} \leq \frac{Cap_{48}}{(r_{37}+r_{38})} \cdot l_{48} \end{array} \right. \quad (4.50)$$

The following Figure 4.13 shows the resulting actualized loads with DR participation considering only load shifting, not load shedding—loads shifted to the time slots $t = 39$ and $t = 40$ as a result of the optimization of the costs considering stochastic conditions.

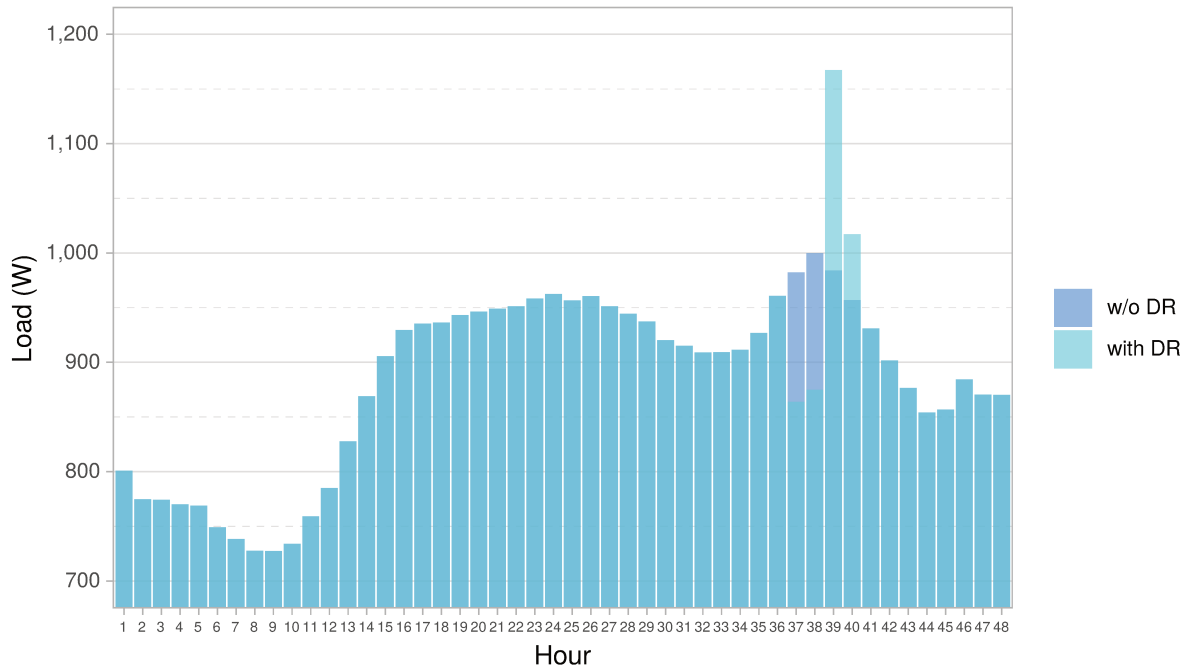


Figure 4.13: Actualized Load Comparison between without DR and with DR Participation in NEBEF Mechanism (W)

In this situation, the differential of benefits is $\Delta B = B_1 - B_0 = 0.01053191$, and the differential of costs is $\Delta C = C_1 - C_0 = 6.076184$. Therefore, the ratio of cost-benefit differential (θ) is $\theta = \frac{\Delta C}{\Delta B} = 576.9307$.

In the following Figure 4.14, the red point represents the coordinates of ΔB and ΔC , and θ means the slope of the line which connects the origin with the red point. As can be seen in the Figure, the red point is out of the grey zone and the value of θ is much greater than the value of ϕ . That means the net benefits with the DR participation are less than the net benefits without the DR participation, and therefore the residential client will decide not to participate in it.

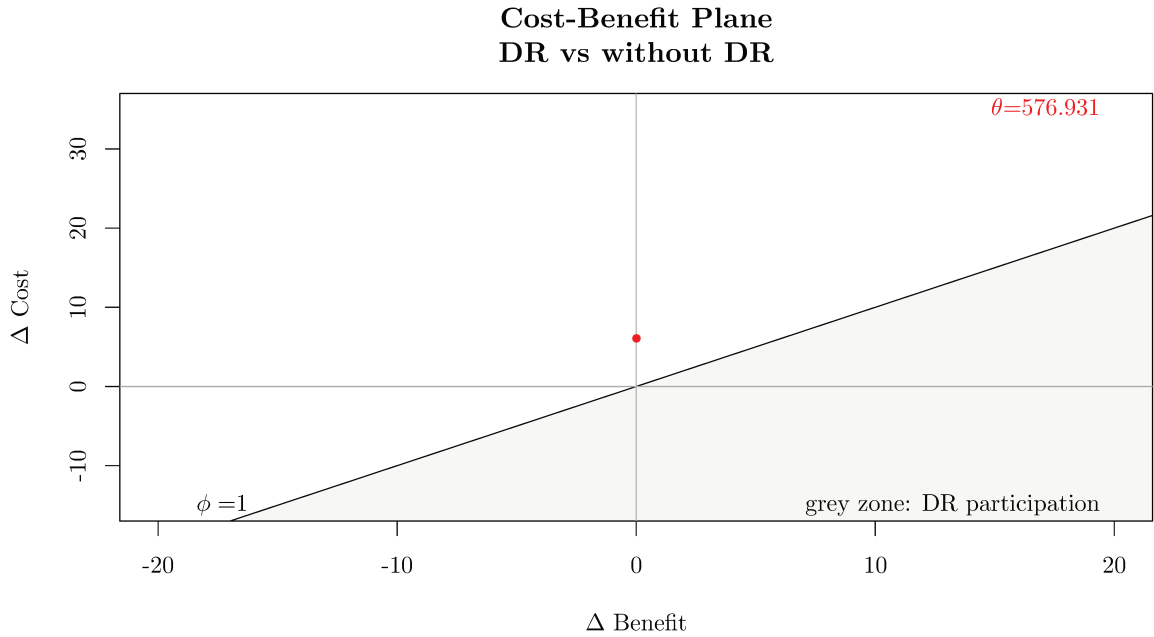


Figure 4.14: Cost-Benefit Plane: DR vs. without DR (NEBEF, Load Shifting)

4.5 Sensitivity Analysis

SA is the study of how the variation (uncertainty) in the output of a statistical model can be attributed to different variations in the inputs of the model (Saltelli et al., 2008; Sharifi et al., 2016), and a method for systematically changing variables (parameters) in a model to correctly predict the resulting impact on the outputs (Sharifi et al., 2016).

In order to deal with uncertainty, scenarios and a SA are useful components of the CBA. The goal of the SA is to find the range of variables that lead to a positive outcome of a CBA in order to understand the robustness of the analysis. The approach to scenarios and sensitivities that has been developed to do so is designed to identify the ‘breaking points’ (thresholds) of the DR policy. That is, in which set of circumstances and assumptions the modeled policy does turn from net positive to negative (or vice versa) (Hoch et al., 2014, p. 5).

For the SA, it is possible to set up a couple of scenarios under different assumptions regarding its design and implementation: a plausible, internally consistent and robust DR base (reference) case, a corresponding counterfactual case (the ‘without DR’ case), and other cases with more constraints on assumptions, with the variations of key parameters. In the protocol of California Public Utilities Commission (CPUC) (2010, p. 12), it is said that the key variables are the variables that are 1) substantially uncertain and 2) likely to have a significant impact on the main test calculations. Therefore, the main parameters or variables for scenarios and SA can be underlying demand—including the needs for additional generation capacity or withdrawal of capacity—, retail tariff, SMP, the level of remuneration for DR resources, the proportion of the LA’s profit to the remuneration, temperature, discount rate, time horizon (like capital amortization period), CO₂ prices or fuel prices, and so forth.

4.5.1 SA for the CBA of the South Korean Case

Following the CBA and Decision-making Analysis of the residential sector in South Korea in the Section 4.3, under the conditions (assumptions) of the ‘reference scenario’ with DR program, in order to represent the possible different situations in terms of the stochastic characteristics of the acceptable capacities for every time slot, I have simulated 1,000 times with 1,000 different vectors of **Cap**, and obtained the mean value of θ . Figure 4.15 shows the result of the simulation, where the 1,000 grey points represent the 1,000 times of the simulation and the red point indicates the mean value of θ . The value of θ was 0.810 with one specific **Cap** vector in Subsection 4.3.2 on the page of 113, but as I increase the number of simulation times, it is approaching to the value of 0.886. Therefore, under these conditions, where the β value is 0.5 and the uniform tariff scheme, linear inconvenience cost function, we can conclude that the average value of θ is 0.886. It means that the ϕ value should be at least equal to 0.886 or greater than this—1 is the maximum value for ϕ . In other words, it means that the transfer from an LA to the DR participants must be higher than 88.6% of the SMP paid to create incentives for consumers to participate in the DR program. This result gives an insight for LAs in terms of the incurred management costs of DR programs.

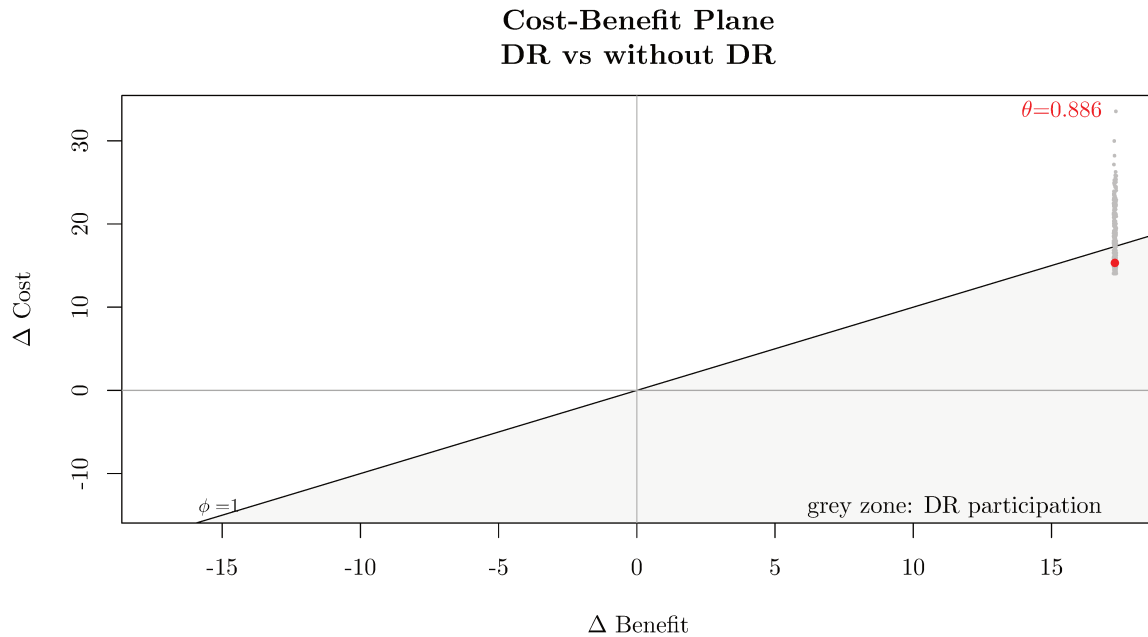


Figure 4.15: 1,000 Time Simulation in terms of the Different Values of ‘Cap’ Variable and Mean θ Value

4.5.1.1 Impacts of the Changes in the Value of β

Figure 4.16 shows the SA in which I verified the value of θ according to the different β values, from 0.5 to 1.5 increasing by 0.1 (Box 4.4). As the β value means the relative value of the inconvenience to the present value of the electricity consumption at the time slot of the DR event, increasing β value means that a residential client will be more reluctant to participate in a DR program where the residential client is asked not to consume the electricity now but asked to shift one’s electricity consumption to backward (before the DR event time slots) or delay forward (after the DR event time slots). In the Figure, 11 sets of 1,000-time simulations for each β value have done, and 11 points indicate the mean θ values corresponding to each β value. As can be seen, the points of the average θ values between $\beta = 0.6$ and $\beta = 1.5$ are out of the maximum ϕ line. Therefore if β values are between 0.6 and 1.5, this DR program cannot attract this residential client to participate in even if it is paid at the maximum level of the DR remuneration ($\phi = 1$).

Box 4.4: Assumption Changes from 'Reference Scenario': Inconvenience Costs (South Korean DTRM)

1. Required flexibility level:

- 40% $\Rightarrow r^{40}$

2. CBL estimation method:

- CBL^{WMA} + SAA

3. Tariff scheme:

- uniform tariff scheme both for No DR participation and DR participation
- 0.124 Korean Won, ₩/Wh, $p^u = c = 0.124, t \in T = \{1, 2, \dots, 24\}$

4. Inconvenience costs:

- $\beta = 0.5$

5. SMP:

- SMPs of DR event day (2016-08-12)

1. Required flexibility level:

- 40% $\Rightarrow r^{40}$

2. CBL estimation method:

- CBL^{WMA} + SAA

3. Tariff scheme:

- uniform tariff scheme both for No DR participation and DR participation
- 0.124 Korean Won, ₩/Wh, $p^u = c = 0.124, t \in T = \{1, 2, \dots, 24\}$

4. Inconvenience costs:

- $\beta = 0.5-1.5$, by 0.1

5. SMP:

- SMPs of DR event day (2016-08-12)



Cost-Benefit Plane
Sensitivity Analysis according to β

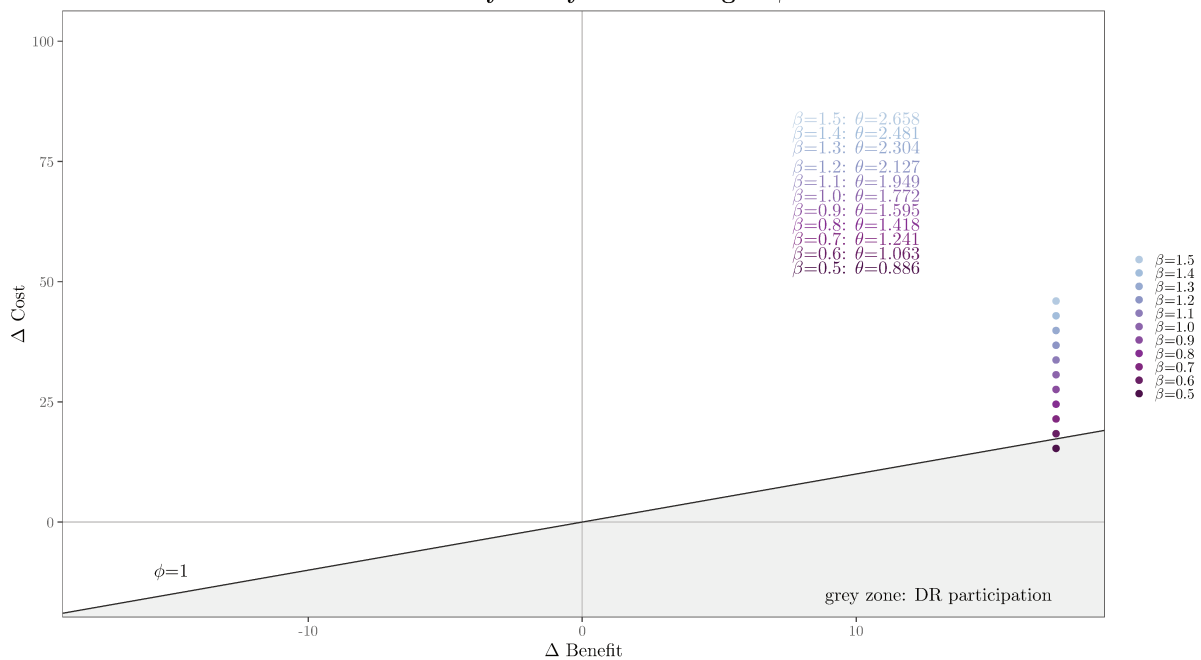


Figure 4.16: Sensitivity Analysis according to the Values of β (South Korean DRTM)

As can be seen in Figure 4.17, almost all the points of the 1,000-time simulations for $\beta = 0.5$ are below the maximum ϕ level, and all the other distributions show that it is out of the sustainable area (the grey area in the Cost-Benefit Plane). Therefore, we can conclude that in this scenario with the uniform tariff scheme, linear inconvenience cost function, it is difficult to attract residential clients who value the present electricity consumption high and have some constraints to shift their electricity consumption to other time slots, which means low flexibility, and it needs to pay more incentives or to come up with a different DR program design, like some subsidies or ToU tariff scheme to motivate them to participate in the DR program.

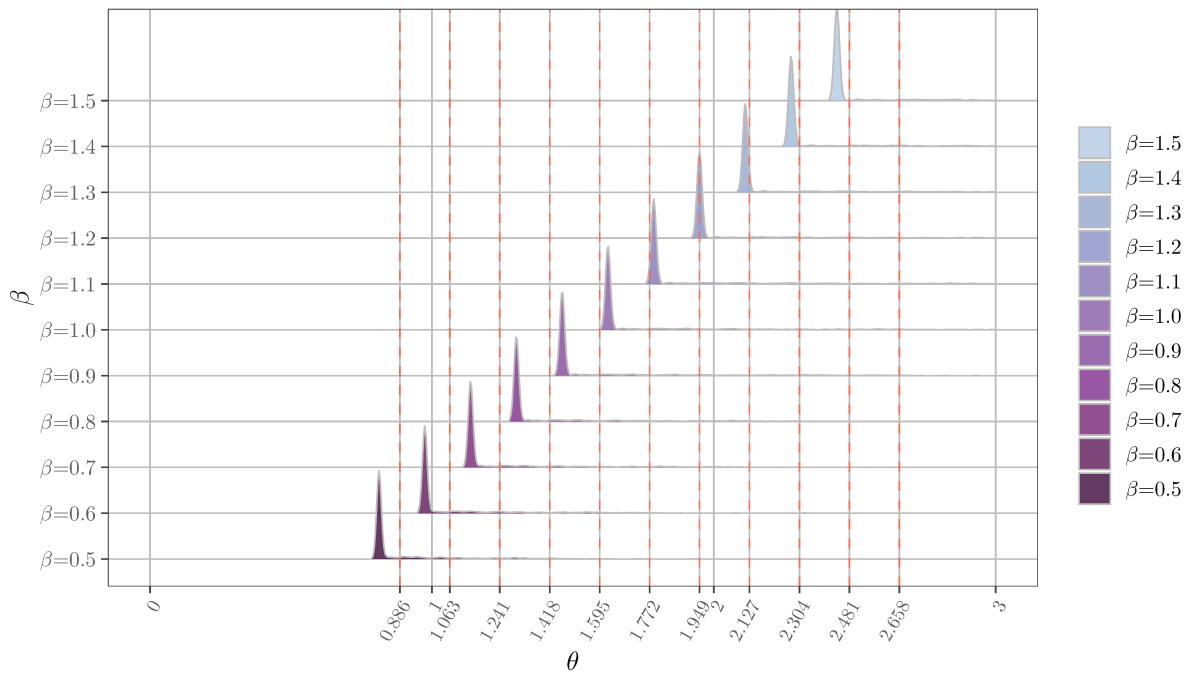


Figure 4.17: The Distribution of the θ Value for Each β Level (South Korean DRTM)

4.5.1.2 Impacts of the Changes in the Tariff Scheme

Figure 4.18 and 4.19 show the SA in which I verified the value of θ according to the change of the tariff scheme from the uniform tariff scheme to the ToU tariff scheme (Box 4.5). Compared to the case with the uniform tariff scheme, the θ values decreased a little bit, and as a result, the point with $\beta = 0.6$ moved into the 'grey zone: DR participation'. It means that this South Korean DRTM with the ToU tariff scheme increases the motivations of participation. However, it should be noted that those customers with higher inconvenience costs ($\beta = 0.7-1.5$) are still out of the 'grey zone: DR participation'. Therefore, for them, there should be a more vivid difference between the off-peak period and peak period in terms of the tariff (clearer price differentiation).

Box 4.5: Assumption Changes from 'Reference Scenario': Tariff Scheme (South Korean DTRM)

1. Required flexibility level:

- 40% $\Rightarrow r^{40}$

2. CBL estimation method:

- CBL^{WMA} + SAA

3. Tariff scheme:

- uniform tariff scheme both for No DR participation and DR participation
- 0.124 Korean Won, ₩/Wh,
 $p^u = c = 0.124, t \in T = \{1, 2, \dots, 24\}$

\Rightarrow

1. Required flexibility level:

- 40% $\Rightarrow r^{40}$

2. CBL estimation method:

- CBL^{WMA} + SAA

3. Tariff scheme:

- Time-ou-Use (ToU) tariff scheme both for No DR participation and DR participation
- $p^{tou} = p_t^{tou}, t \in T = \{1, 2, \dots, 24\}$

4. Inconvenience costs:

- $\beta = 0.5-1.5$, by 0.1

5. SMP:

- SMPs of DR event day (2016-08-12)

4. Inconvenience costs:

- $\beta = 0.5-1.5$, by 0.1

5. SMP:

- SMPs of DR event day (2016-08-12)



Cost-Benefit Plane
Sensitivity Analysis according to Change of Tariff Scheme (ToU)

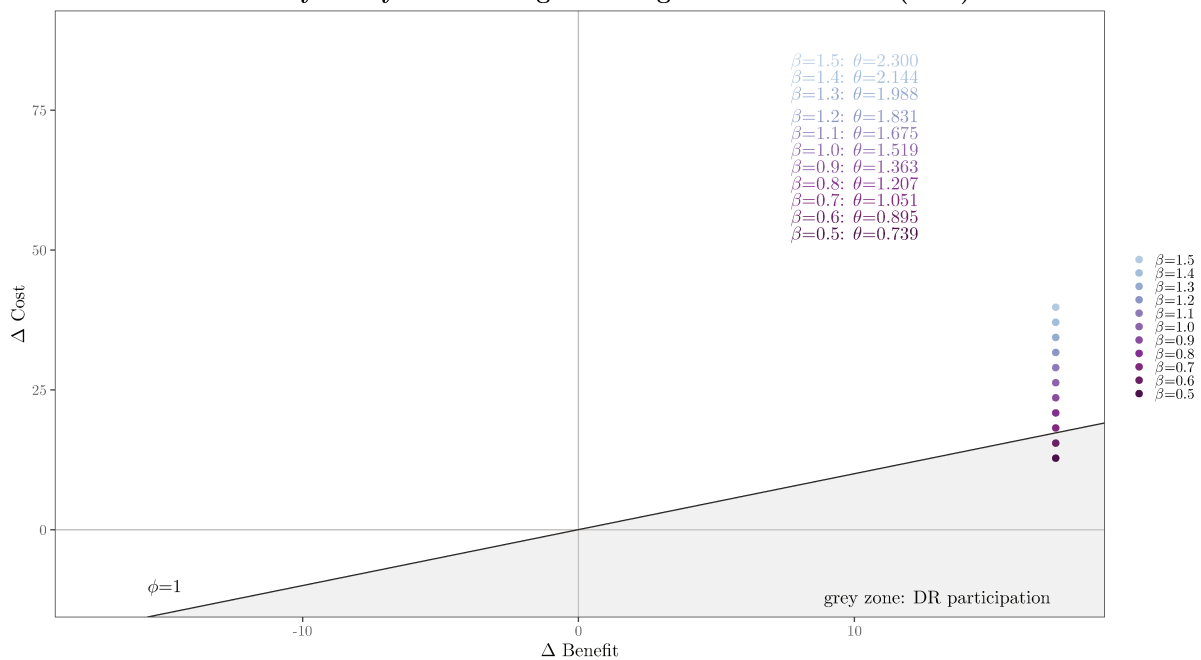


Figure 4.18: Sensitivity Analysis according to Change of Tariff Scheme (ToU) (South Korean DRTM)

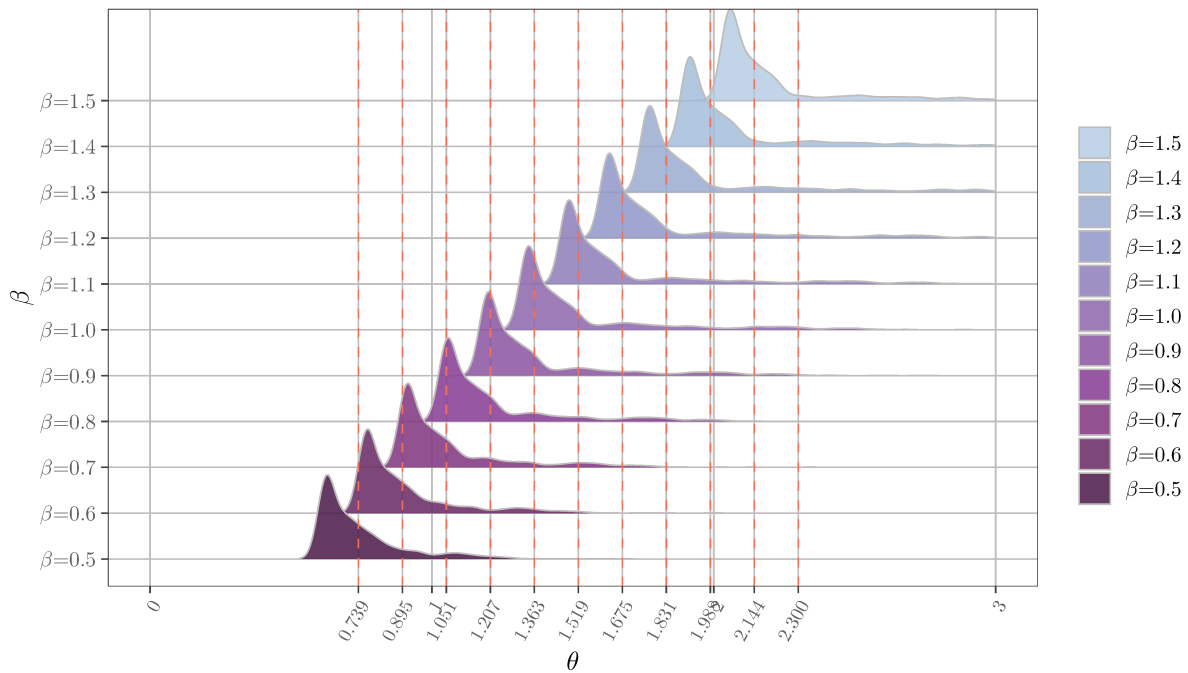


Figure 4.19: The Distribution of the θ Value for Each β Level according to Change of Tariff Scheme (ToU) (South Korean DRTM)

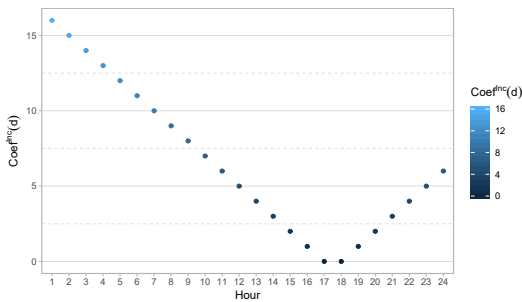
4.5.1.3 Impacts of the Changes in the Form of the Function $\text{coef}^{\text{INC}}(d)$

This time, I have changed the functional form of the inconvenience function from the linear function to the exponential function based on the ToU tariff scheme (Box 4.6). Figure 4.20 and 4.21 show the result that with the exponential inconvenience function, it decreased the costs, and therefore, all the points are now in the DR participation grey zone. The reason why the costs decreased is that even though with the exponential function, the demand reduction shifted to the very near time slots, for example, $t = 16$ or $t = 19$, the increasing rate of the inconvenience costs is relatively slower than that of the linear inconvenience function for the very near time slots. Therefore, we can see that the clients' DR participation decisions are very sensitive to the specific functional form of the inconvenience costs function. It implies that the DR system operator should pay more attention to the consumer's inconvenience costs function as well as the β value.

Box 4.6: Assumption Changes from 'Reference Scenario': Different Form of Function $\text{Coef}^{\text{INC}}(d)$ based on ToU (South Korean DTRM)

1. Required flexibility level:
 - 40% $\Rightarrow r^{40}$
2. CBL estimation method:
 - $\text{CBL}^{\text{WMA}} + \text{SAA}$
3. Tariff scheme:
 - Time-ou-Use (ToU) tariff scheme both for No DR participation and DR participation,
 - $\mathbf{p}^{\text{tou}} = p_t^{\text{tou}}, t \in T = \{1, 2, \dots, 24\}$

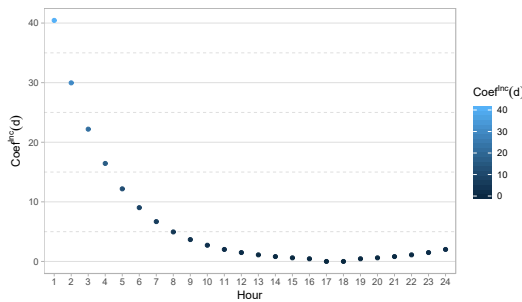
4. Inconvenience costs:
 - $\beta = 0.5-1.5$, by 0.1
 - **linear function of $\text{Coef}^{\text{INC}}(d)$**



5. SMP:
 - SMPs of DR event day (2016-08-12).

1. Required flexibility level:
 - 40% $\Rightarrow r^{40}$
2. CBL estimation method:
 - $\text{CBL}^{\text{WMA}} + \text{SAA}$
3. Tariff scheme:
 - Time-ou-Use (ToU) tariff scheme both for No DR participation and DR participation,
 - $\mathbf{p}^{\text{tou}} = p_t^{\text{tou}}, t \in T = \{1, 2, \dots, 24\}$

4. Inconvenience costs:
 - $\beta = 0.5-1.5$, by 0.1
 - **exponential function of $\text{Coef}^{\text{INC}}(d)$**



5. SMP:
 - SMPs of DR event day (2016-08-12).



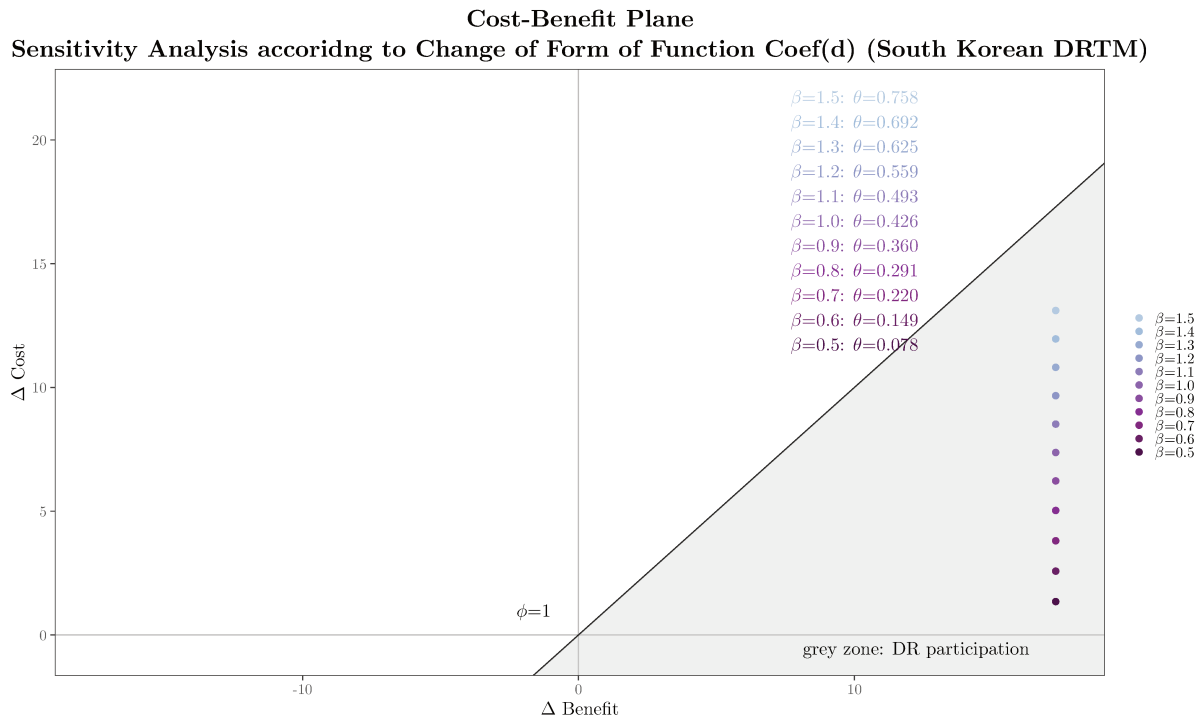


Figure 4.20: Sensitivity Analysis according to Change of Form of Function Coef(d) (South Korean DRTM)

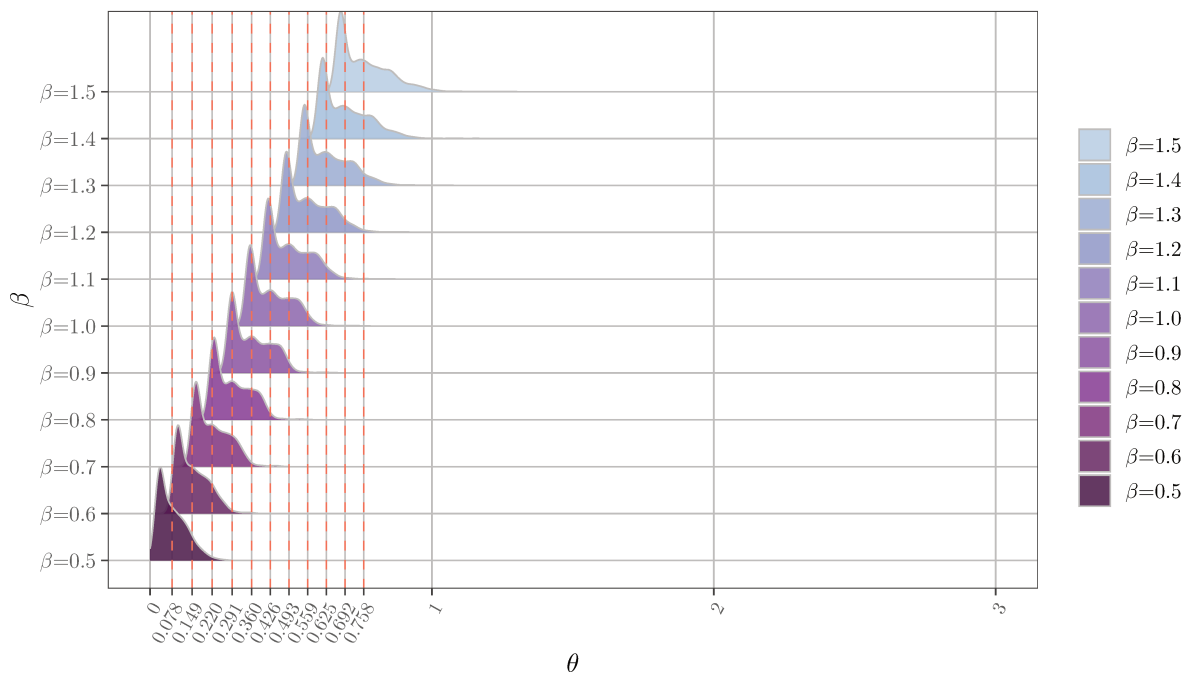


Figure 4.21: The Distribution of the θ Value for Each β Level according to Change of Form of Function Coef(d) (South Korean DRTM)

4.5.1.4 Impacts of the Changes in the SMP (Highest and Lowest)

So far I have done the CBAs with the factual SMPs on the DR event day, August 12, 2016. However, the potential DR participants will make their decisions depending on the expectations on the SMPs, and ex-post they will be paid at the level of realized SMPs. In that sense, SMP is quite an important variable. Therefore, I have conducted the SA with the highest SMPs and the lowest SMPs in 2016 in order to confirm its sensitivity (Box 4.7 and Fig. 4.22).

Box 4.7: Assumption Changes from 'Reference Scenario': Highest & Lowest SMPs (South Korean DTRM)

1. Required flexibility level:

- 40% $\Rightarrow r^{40}$

2. CBL estimation method:

- $CBL^{WMA} + SAA$

3. Tariff scheme:

- uniform tariff scheme both for No DR participation and DR participation
- 0.124 Korean Won, ₩/Wh,
 $p^u = c = 0.124, t \in T = \{1, 2, \dots, 24\}$

4. Inconvenience costs:

- $\beta = 0.5-1.5$, by 0.1

5. SMP:

- SMPs of DR event day (2016-08-12)

\Rightarrow

1. Required flexibility level:

- 40% $\Rightarrow r^{40}$

2. CBL estimation method:

- $CBL^{WMA} + SAA$

3. Tariff scheme:

- uniform tariff scheme both for No DR participation and DR participation
- 0.124 Korean Won, ₩/Wh,
 $p^u = c = 0.124, t \in T = \{1, 2, \dots, 24\}$

4. Inconvenience costs:

- $\beta = 0.5-1.5$, by 0.1

5. SMP:

- Highest SMPs (2016-01-27)
- Lowest SMPs (2016-02-08)

↑

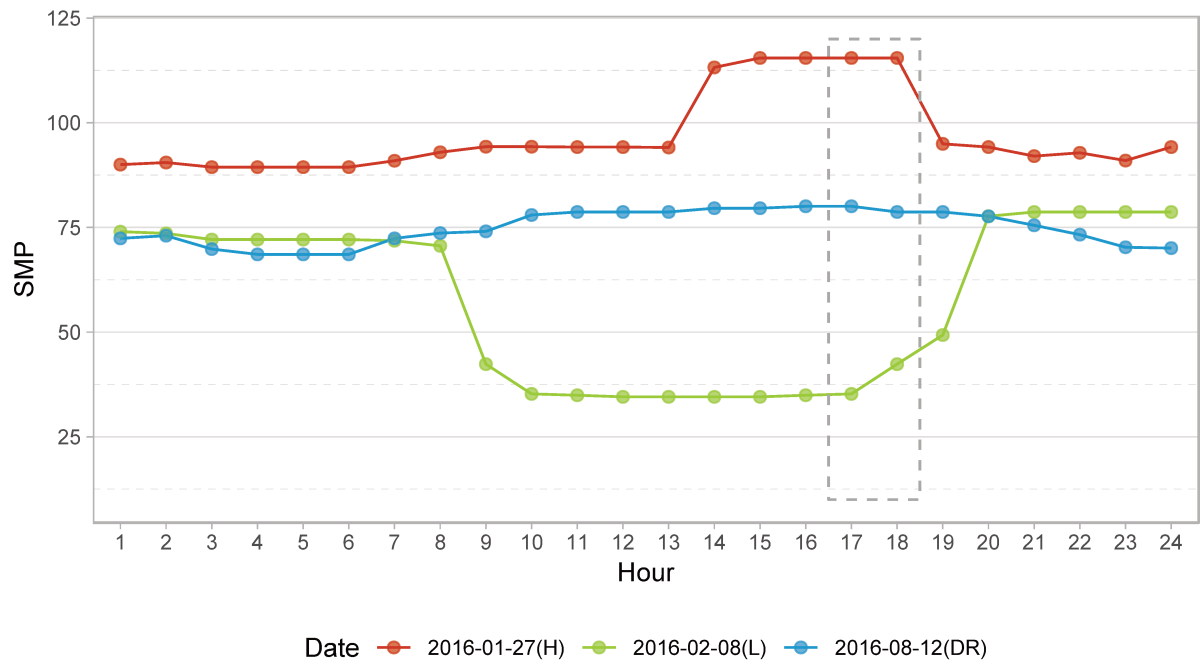


Figure 4.22: Highest & Lowest SMPs, South Korea in 2016 (Korean Won (₩)/kWh)

Source: "SMP". KPX, [On-line], Available: <http://www.kpx.or.kr/www/contents.do?key=225>

As can be easily expected, with the highest SMPs it increases the benefits with the DR participation, therefore, the points with β values of 0.6-0.8 moved into the grey DR participation zone (rightward horizontal shifts) (Fig. 4.23 and 4.24). With the lowest SMPs it decreased the benefits, and the points moved in the opposite direction—leftward horizontal shifts (Fig. 4.25 and 4.26). As a result, no point is in the grey DR participation zone.

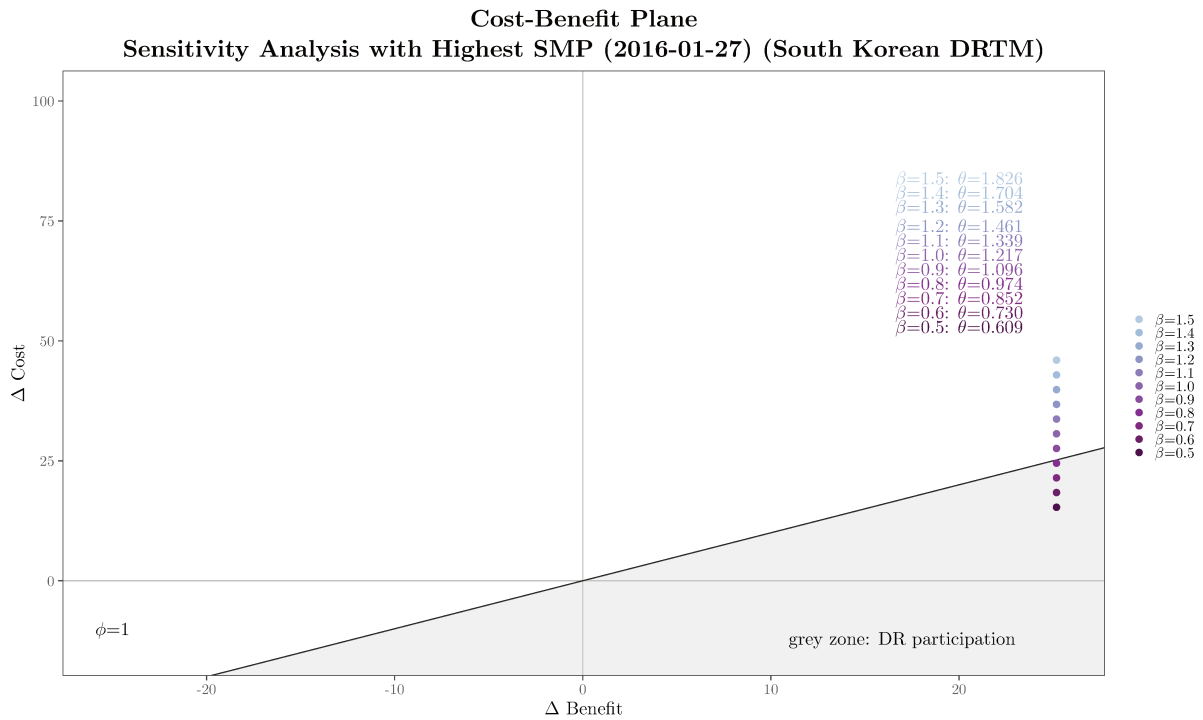


Figure 4.23: Sensitivity Analysis according to Change of SMPs (Highest, South Korean DRTM)

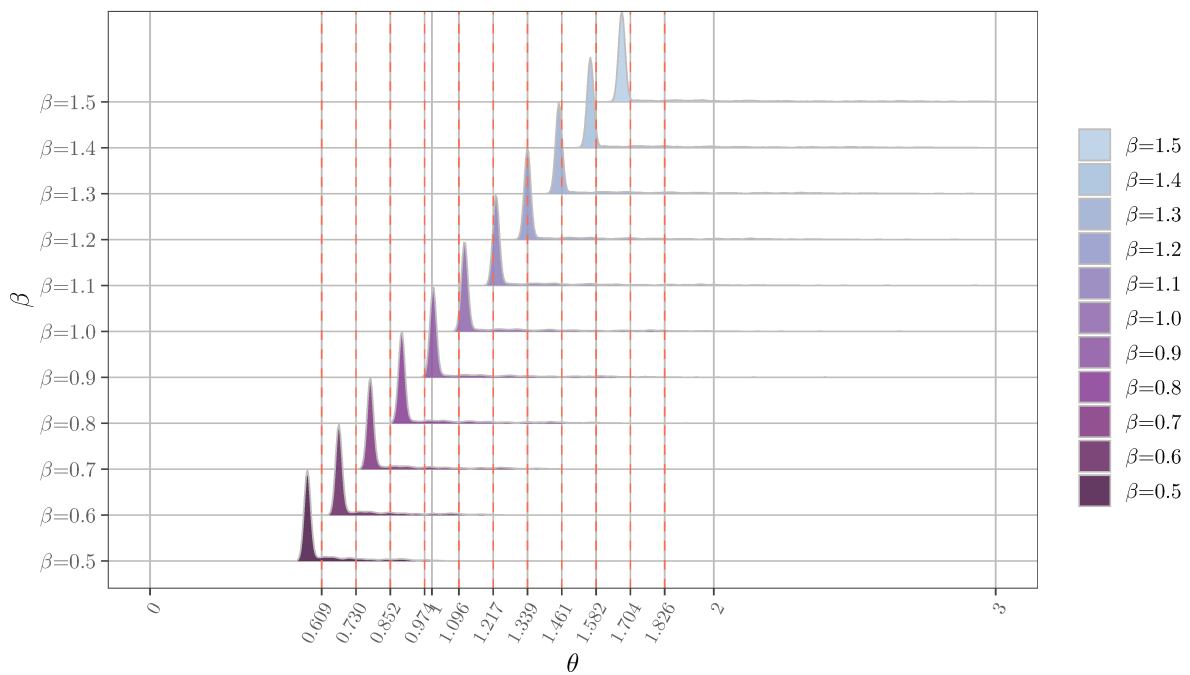


Figure 4.24: The Distribution of the θ Value for Each β Level according to Change of SMPs (Highest, South Korean DRTM)

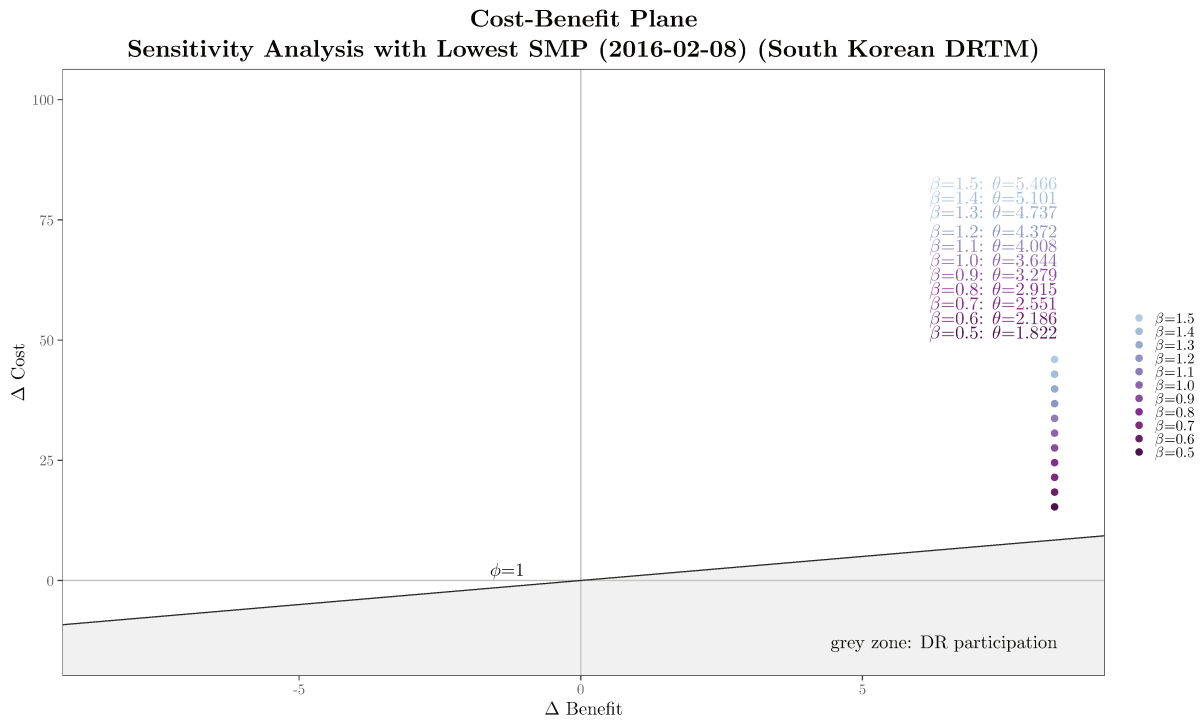


Figure 4.25: Sensitivity Analysis according to Change of SMPs (Lowest, South Korean DRTM)

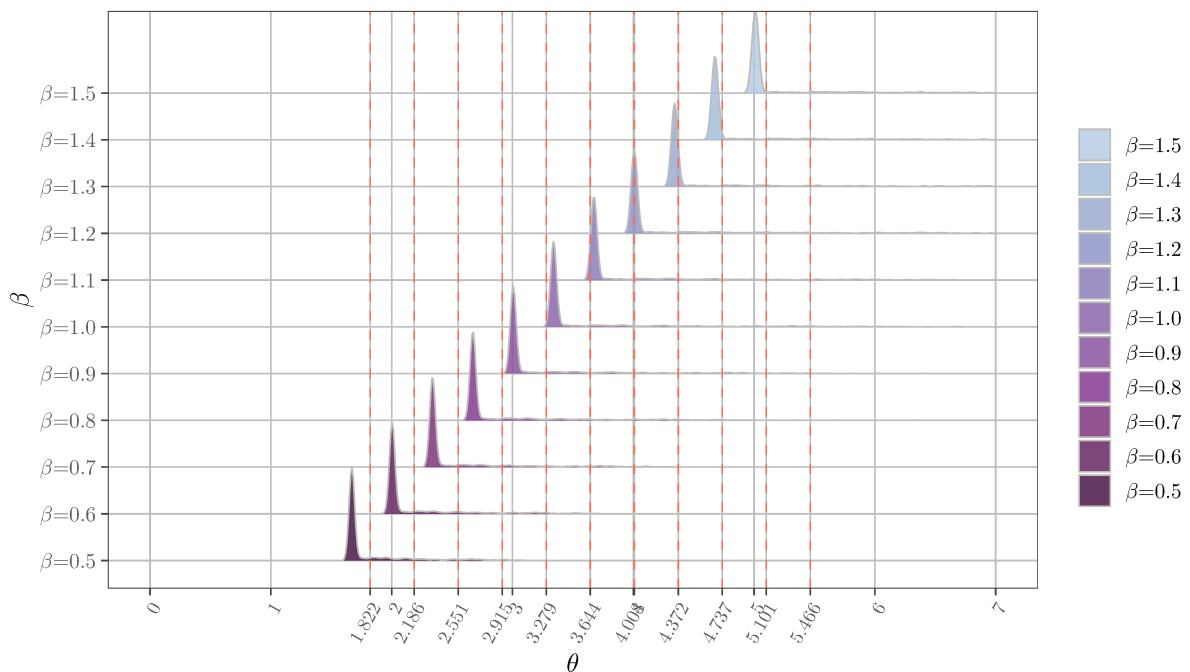


Figure 4.26: The Distribution of the θ Value for Each β Level according to Change of SMPs (Lowest, South Korean DRTM)

The following Figure 4.27 illustrates the SMP that makes the net benefit 0, zero, for each β value in South Korean DRTM. Therefore, these SMPs are the thresholds. In more detail, for example, for a participant who has a value of $\beta = 0.5$, the SMP should be more than 67.11 ₩/kWh in order to have positive or zero net

benefit. Likewise, for a participant who has a value of $\beta = 1.5$, the SMP should be more than 201.75 ₩/kWh in order to have positive or zero net benefit. For your reference, the SMP for $t = 17$ on August 12, 2016, it was 80.05 ₩/kWh—the dash and dot line in green. Actually, these break-even points of SMP are conceptually very similar to NBTP introduced in South Korean DRTM following the DR markets in the U.S., especially PJM. The NBTP is the price that makes the decrease in purchasing costs of electricity for retailers equal to the payments for DR resources. Therefore, it is the break-even point from the retailers' perspective. According to NBT, LAs cannot bid below NBTP in South Korean DRTM. Similarly, but in the opposite way, the SMPs that we have calculated here are the break-even points from the DR participants' perspective.

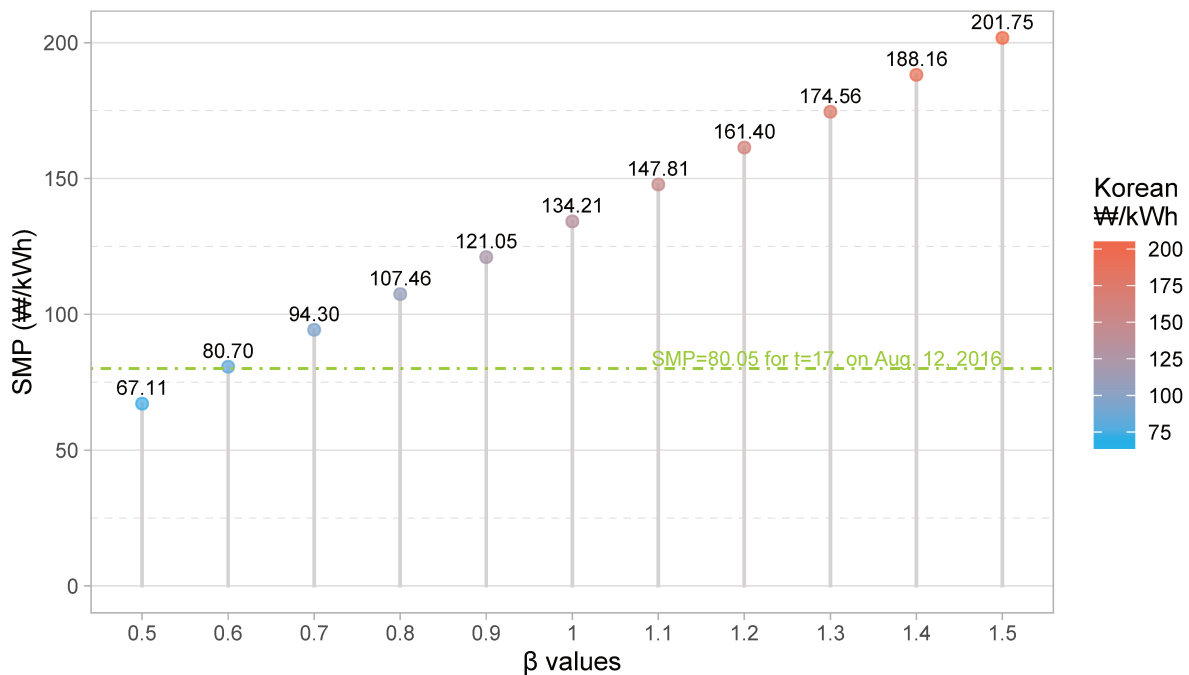


Figure 4.27: Threshold SMP of Net Benefit for Each β Value (South Korean DRTM, ₩/ kWh)

4.5.2 SA for the CBA of the French Case

In this subsection, following the CBA and Decision-making analysis for the French NEBEF mechanisms in Section 4.4, SAs will be done according to the change in the value of β , the change of the CBL estimation method, the change of the tariff scheme, the change of the form of the inconvenience cost function, and the change of the SMPs.

4.5.2.1 Impacts of the Changes in the Value of β

In a similar way with the South Korean case, the impacts of the change in the value of β are observed from $\beta = 0.5$ to $\beta = 1.5$ increasing by 0.1 (Box 4.8). In the upper panel of Figure 4.28 for the load shedding case of NEBEF, there are eleven points with different colors corresponding to its β values. As β values are increasing it is vertically shifting upwards, and up to the point of $\beta = 1$ those are in the grey zone, which means the DR participation, but after this point the remaining points are out of the grey zone, which means there is no incentive to participate in the DR program for this residential client.

Box 4.8: Assumption Changes from 'Reference Scenario': Inconvenience Costs (French NEBEF)

1. Target flexibility level:

- 40% $\Rightarrow r^{40}$

2. CBL estimation method:

- CBL^{avg.10}

3. Tariff scheme:

- uniform tariff scheme
- 0.01648 cts €/Wh, $p^u = c = 0.01648$,
 $t \in T = \{1, 2, \dots, 48\}$

4. Inconvenience costs:

- $\beta = 0.5$

5. SMP:

- SMPs of DR event day (2016-01-18)

1. Target flexibility level:

- 40% $\Rightarrow r^{40}$

2. CBL estimation method:

- CBL^{avg.10}

3. Tariff scheme:

- uniform tariff scheme
- 0.01648 cts €/Wh, $p^u = c = 0.01648$,
 $t \in T = \{1, 2, \dots, 48\}$

4. Inconvenience costs:

- $\beta = 0.5-1.5$, by 0.1

5. SMP:

- SMPs of DR event day (2016-01-18)

\Rightarrow



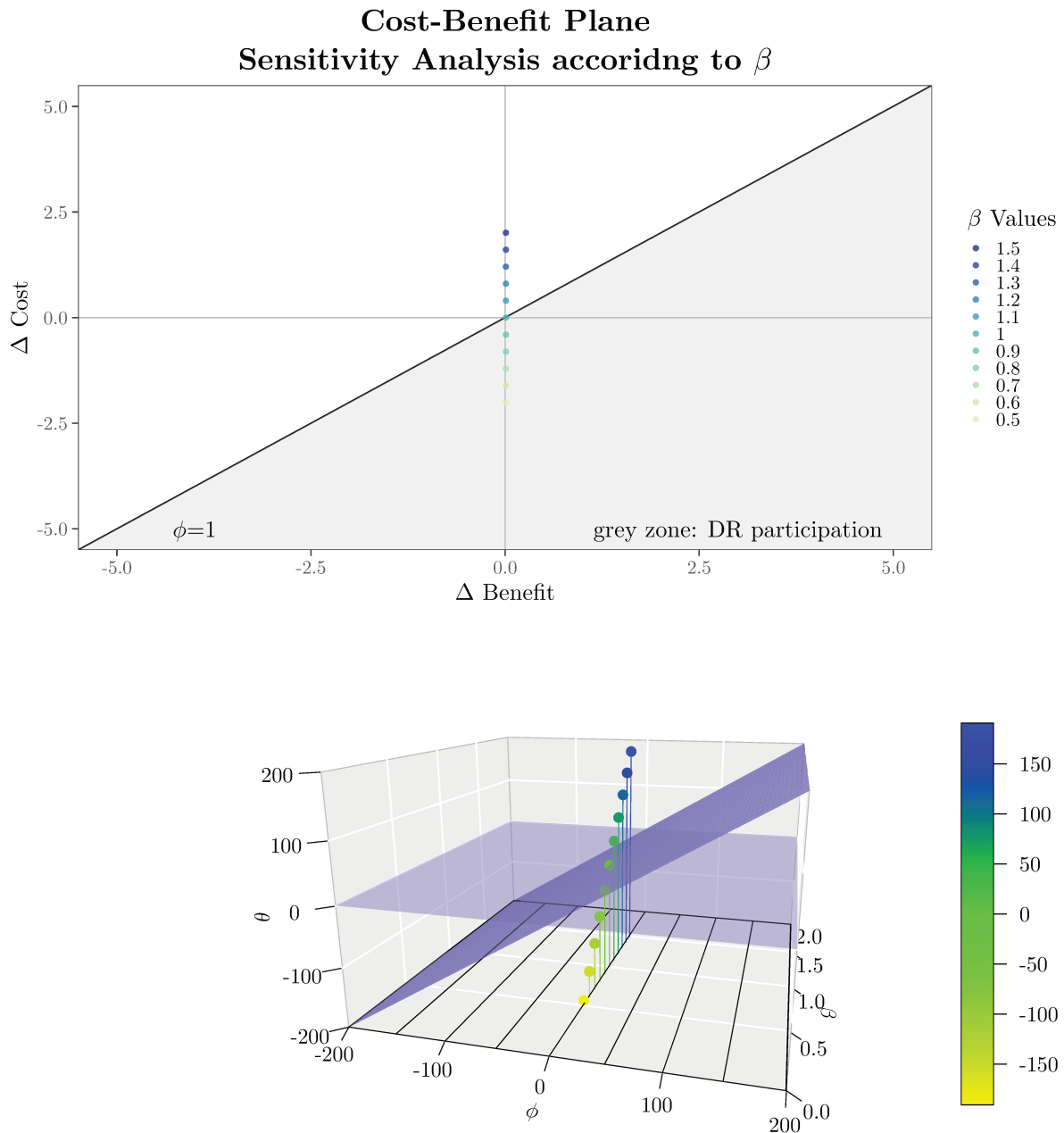


Figure 4.28: Sensitivity Analysis according to the Values of β for NEBEF (Load Shedding)

In the lower panel of the Figure, it represents the same result, but those eleven points are placed in the three-dimensional space— $x - y - z$ axis for ϕ, β , and θ respectively. One of the two purple planes which is parallel with x-y plane is $0 \cdot \phi + 0 \cdot \beta + 1 \cdot \theta = 1$ plane, that is $\theta = 1$ plane. Another purple plane which is diagonal is $1 \cdot \phi + 0 \cdot \beta + 1 \cdot \theta = 0$ plane, that is $\phi = \theta$ plane. Therefore, the space under these plane means the grey zone in the upper panel of the Figure, in which a residential client will decide to participate in the DR program.

In the following Figure 4.29 for the load shifting case of NEBEF, there is no point in the grey zone or under the purple planes. Actually, it was out of the grey zone even with the lowest β value, and with higher β values, it is moving way further from the grey zone.

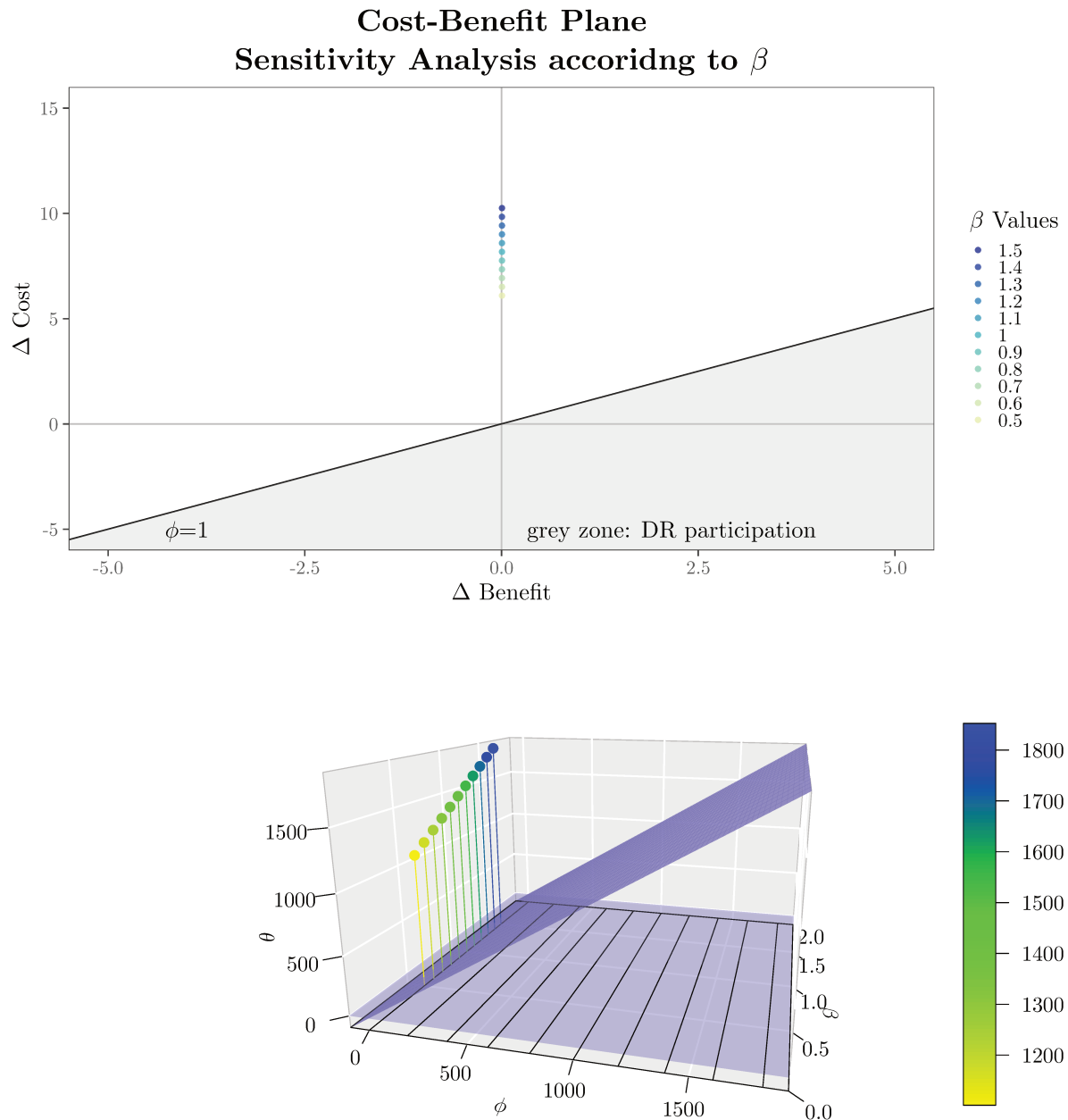


Figure 4.29: Sensitivity Analysis according to the Values of β for NEBEF (Load Shifting)

It is interesting to observe that there are more points in the DR participation zone in the French NEBEF load shedding case than the South Korean DRTM case or the French NEBEF load shifting case. Actually, the reason is that for the load shedding case, the total costs (total tariff + additional inconvenience costs) are relatively lower than that of the load shifting case (the South Korean DRTM and French NEBEF load shifting cases) because, let alone the inconvenience costs, the total tariff has decreased by the reduced loads contrary to the same total tariff for the load shifting cases—that is, the same total electricity consumption for the load shifting case if we assume no partial load shedding at all.

4.5.2.2 Importance of the Accurate CBL Method

In Section 4.4 the CBA and Decision-making Analyses have been done based on the CBL with the estimation method of 'moyenne 10 jours' (an average for 10 days) in the NEBEF mechanism. However, the method does not perform very well and it has high error rate contrary to the CBL estimation method which is utilized in South Korea, which is $CBL^{WMA} + SAA$. Therefore, it is worthwhile applying the latter CBL estimation method to the French NEBEF case and observing the impact of the change of the CBL estimation method (Box 4.9).

Box 4.9: Assumption Changes from 'Reference Scenario': CBL (French NEBEF)

<ol style="list-style-type: none"> 1. Target flexibility level: <ul style="list-style-type: none"> • 40% $\Rightarrow r^{40}$ 2. CBL estimation method: <ul style="list-style-type: none"> • CBL^{avg-10} 3. Tariff scheme: <ul style="list-style-type: none"> • uniform tariff scheme • 0.01648 cts €/Wh, $p^u = c = 0.01648$, $t \in T = \{1, 2, \dots, 48\}$ 4. Inconvenience costs: <ul style="list-style-type: none"> • $\beta = 0.5-1.5$, by 0.1 5. SMP: <ul style="list-style-type: none"> • SMPs of DR event day (2016-01-18) 	\Rightarrow	<ol style="list-style-type: none"> 1. Target flexibility level: <ul style="list-style-type: none"> • 40% $\Rightarrow r^{40}$ 2. CBL estimation method: <ul style="list-style-type: none"> • $CBL^{WMA} + SAA$ 3. Tariff scheme: <ul style="list-style-type: none"> • uniform tariff scheme • 0.01648 cts €/Wh, $p^u = c = 0.01648$, $t \in T = \{1, 2, \dots, 48\}$ 4. Inconvenience costs: <ul style="list-style-type: none"> • $\beta = 0.5-1.5$, by 0.1 5. SMP: <ul style="list-style-type: none"> • SMPs of DR event day (2016-01-18)
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The following Figure 4.30 shows the original points in grey which were the points with different β values, and the new points applied with the CBL estimation method of $CBL^{WMA} + SAA$. The result shows the horizontal shift of the original points to the right. With this horizontal shift to the right resulting from the change of the CBL estimation method, one point ($\beta = 1.1$) moves into the grey zone from out of the grey zone.

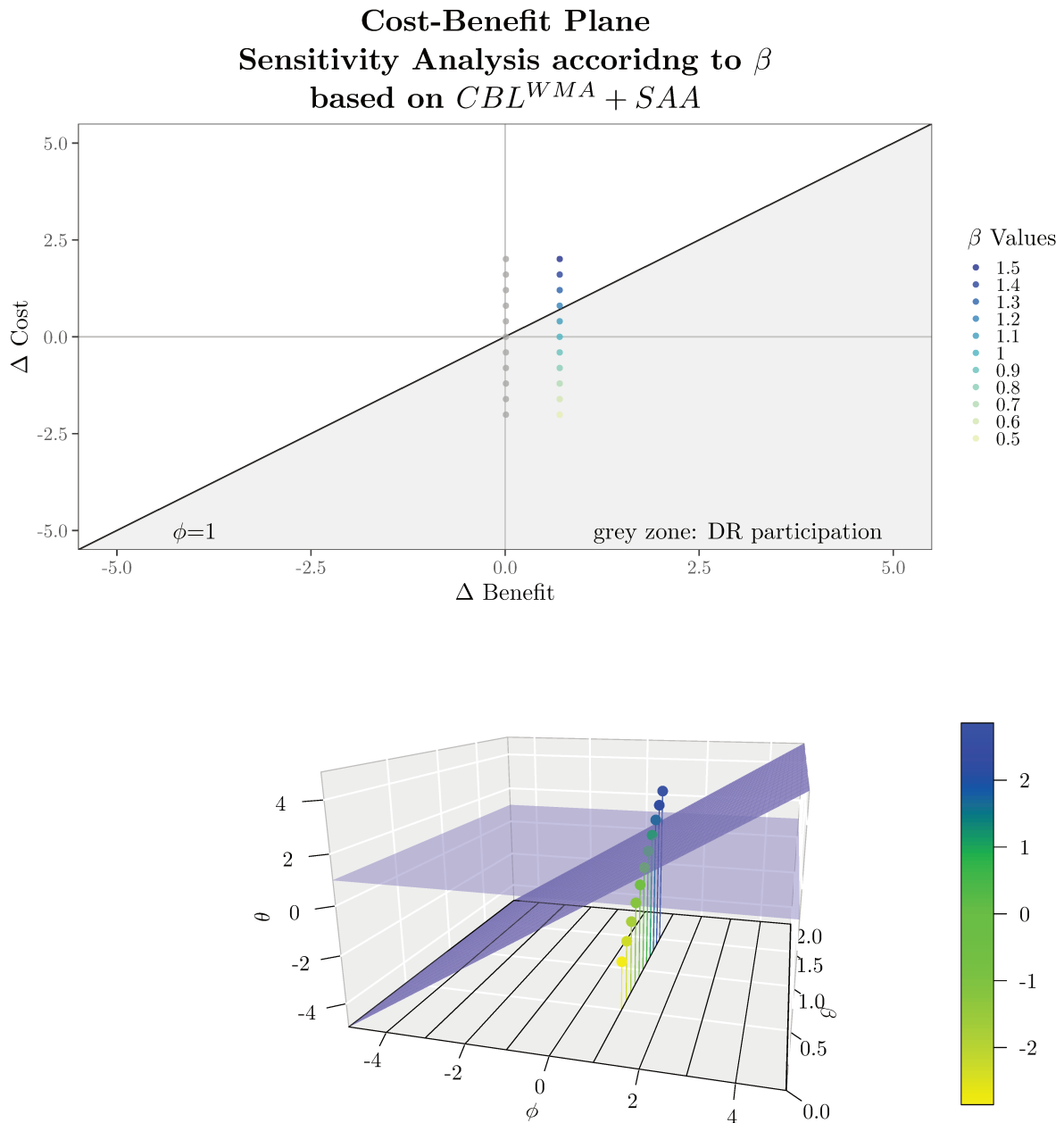


Figure 4.30: Sensitivity Analysis according to the Values of β for NEBEF (Load Shedding) based on the $CBL^{WMA} + SAA$ Method

For the load shifting case of NEBEF in Figure 4.31, despite the change of the CBL estimation method from the inaccurate one to highly accurate one, those eleven points are still out of the grey zone of the DR participation. Even though the differential of benefits increased thanks to the accurate CBL estimation method, the costs due to the load shifting are overwhelming the increased differential of benefits. Therefore, there is no significant status change in terms of the decision-making of a residential client.

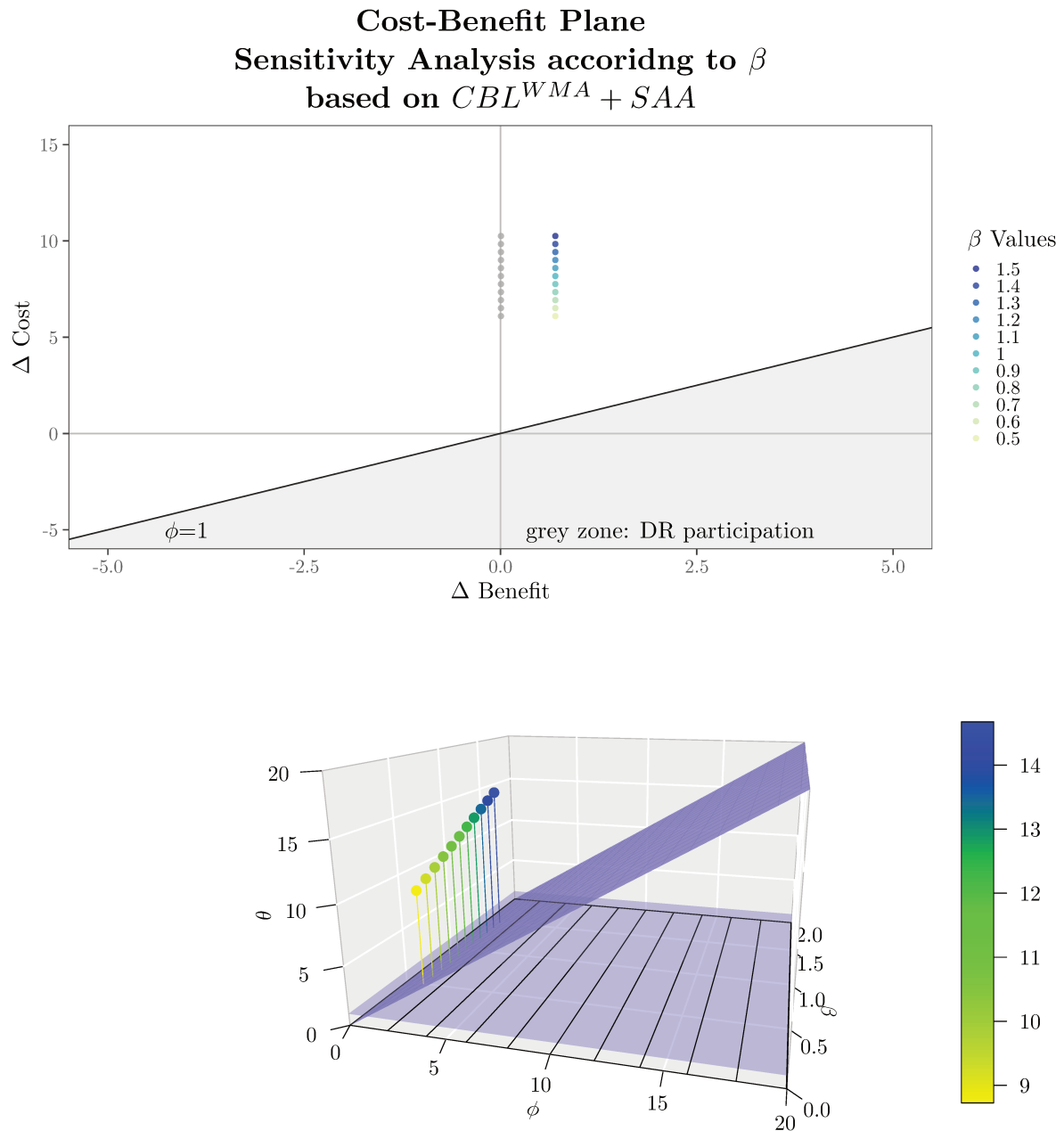


Figure 4.31: Sensitivity Analysis according to the Values of β for NEBEF (Load Shifting) based on the $CBL^{WMA} + SAA$ Method

4.5.2.3 Impacts of the Change of the Tariff Scheme

As changed from the uniform tariff scheme to the ToU tariff scheme (Box 4.10), in the following Figure 4.32 there are subtle vertical shifts for the eleven points, but no significant impacts of the tariff scheme change for the load shedding case of NEBEF. There is also no big difference for the load shifting case of NEBEF with the tariff scheme change to ToU in Figure 4.32.

Box 4.10: Assumption Changes from 'Reference Scenario': Tariff Scheme (French NEBEF)

1. Target flexibility level:

- 40% $\Rightarrow r^{40}$

2. CBL estimation method:

- $CBL^{avg.10}$

3. Tariff scheme:

- **uniform tariff scheme**
- 0.01648 cts €/Wh, $p^u = c = 0.01648$,
 $t \in T = \{1, 2, \dots, 48\}$

\Rightarrow

1. Target flexibility level:

- 40% $\Rightarrow r^{40}$

2. CBL estimation method:

- $CBL^{avg.10}$

3. Tariff scheme:

- **ToU tariff scheme**
- 0.016 cts €/Wh for peak time
- 0.01114 cts €/Wh for off-peak time

4. Inconvenience costs:

- $\beta = 0.5-1.5$, by 0.1

5. SMP:

- SMPs of DR event day (2016-01-18)

4. Inconvenience costs:

- $\beta = 0.5-1.5$, by 0.1

5. SMP:

- SMPs of DR event day (2016-01-18)



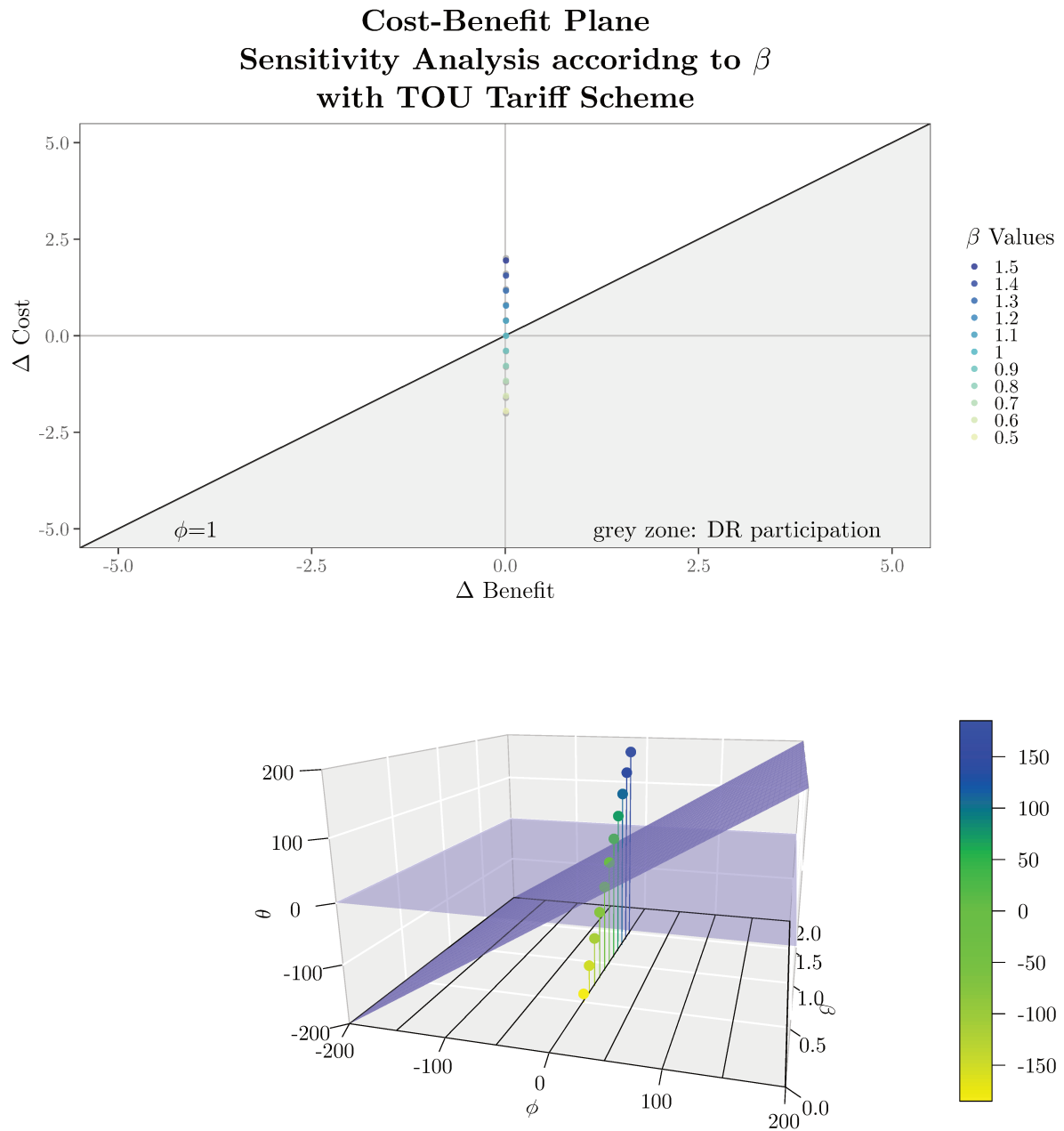


Figure 4.32: Sensitivity Analysis according to the Values of β for NEBEF (Load Shedding) with ToU Tariff Scheme

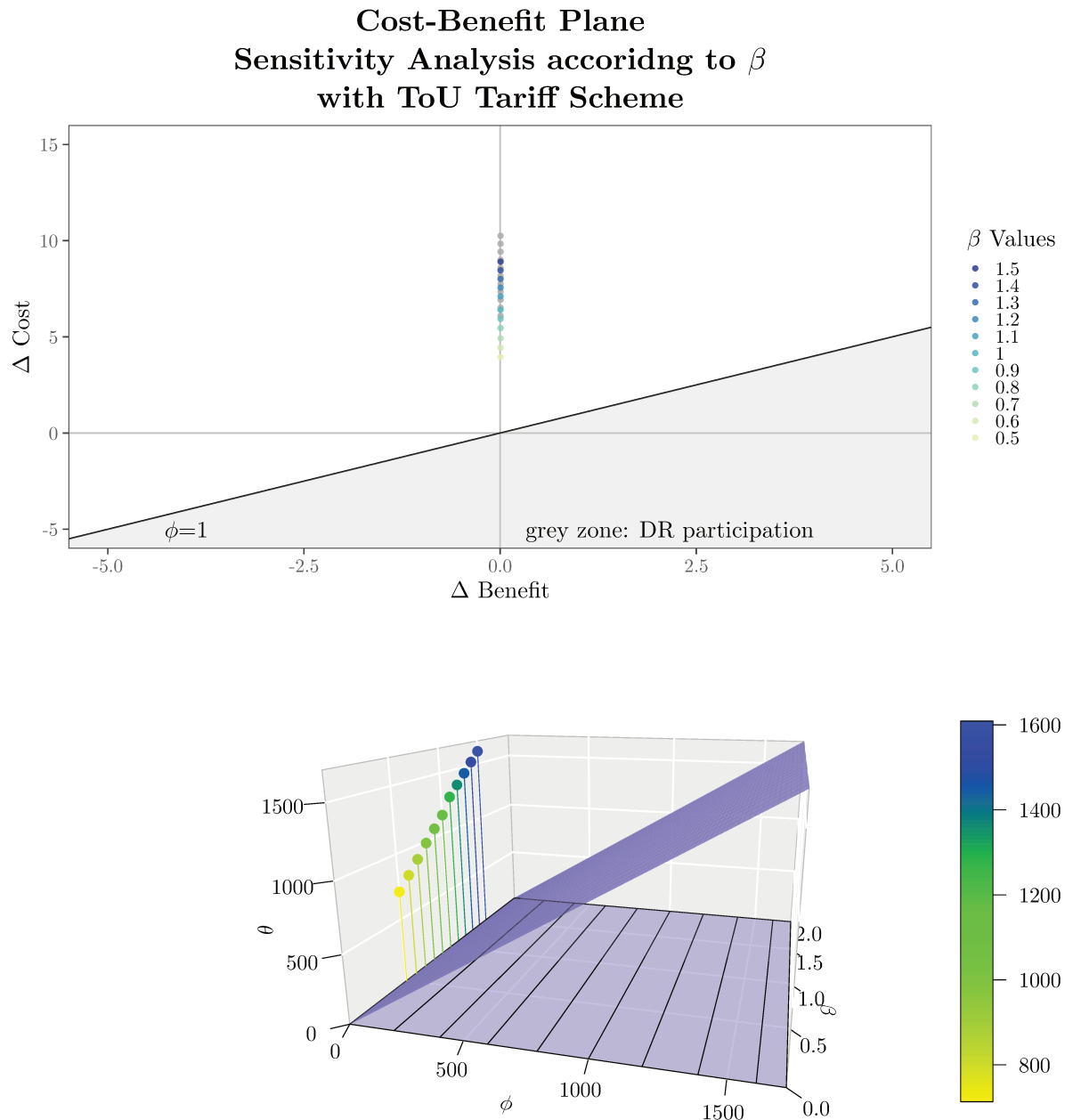


Figure 4.33: Sensitivity Analysis according to the Values of β for NEBEF (Load Shifting) with ToU Tariff Scheme

4.5.2.4 Impacts of the Change of CBL Method and Tariff Scheme

The following two Figures 4.34 and 4.35 show the combined impacts (Box 4.11) of the change of the CBL estimation method and the tariff scheme for the load shedding case and load shifting case of NEBEF respectively. In Figure 4.34 the impacts are not quite different from the result of the change of the CBL estimation method (horizontal shift) because the impacts of the change of the tariff scheme (vertical shift) were too negligible. In contrast, the combined impacts of the CBL estimation method and the change of the tariff scheme for the load shifting case of NEBEF show the diagonal shifts. Although those eleven points are still out of the grey

zone, with the diagonal shifts the lower points are approaching quite close to the ϕ line and the grey zone. It means that in this situation small extra incentives could attract residential clients to participate in the DR program.

Box 4.11: Assumption Changes from 'Reference Scenario': CBL & Tariff Scheme (French NEBEF)

1. Target flexibility level:

- 40% $\Rightarrow r^{40}$

2. CBL estimation method:

- CBL^{avg-10}

\Rightarrow

1. Target flexibility level:

- 40% $\Rightarrow r^{40}$

2. CBL estimation method:

- $CBL^{WMA} + SAA$

3. Tariff scheme:

- uniform tariff scheme
- 0.01648 cts €/Wh, $p^u = c = 0.01648$,
 $t \in T = \{1, 2, \dots, 48\}$

\Rightarrow

3. Tariff scheme:

- ToU tariff scheme
- 0.016 cts €/Wh for peak time
- 0.01114 cts €/Wh for off-peak time

4. Inconvenience costs:

- $\beta = 0.5-1.5$, by 0.1

5. SMP:

- SMPs of DR event day (2016-01-18)

4. Inconvenience costs:

- $\beta = 0.5-1.5$, by 0.1

5. SMP:

- SMPs of DR event day (2016-01-18)



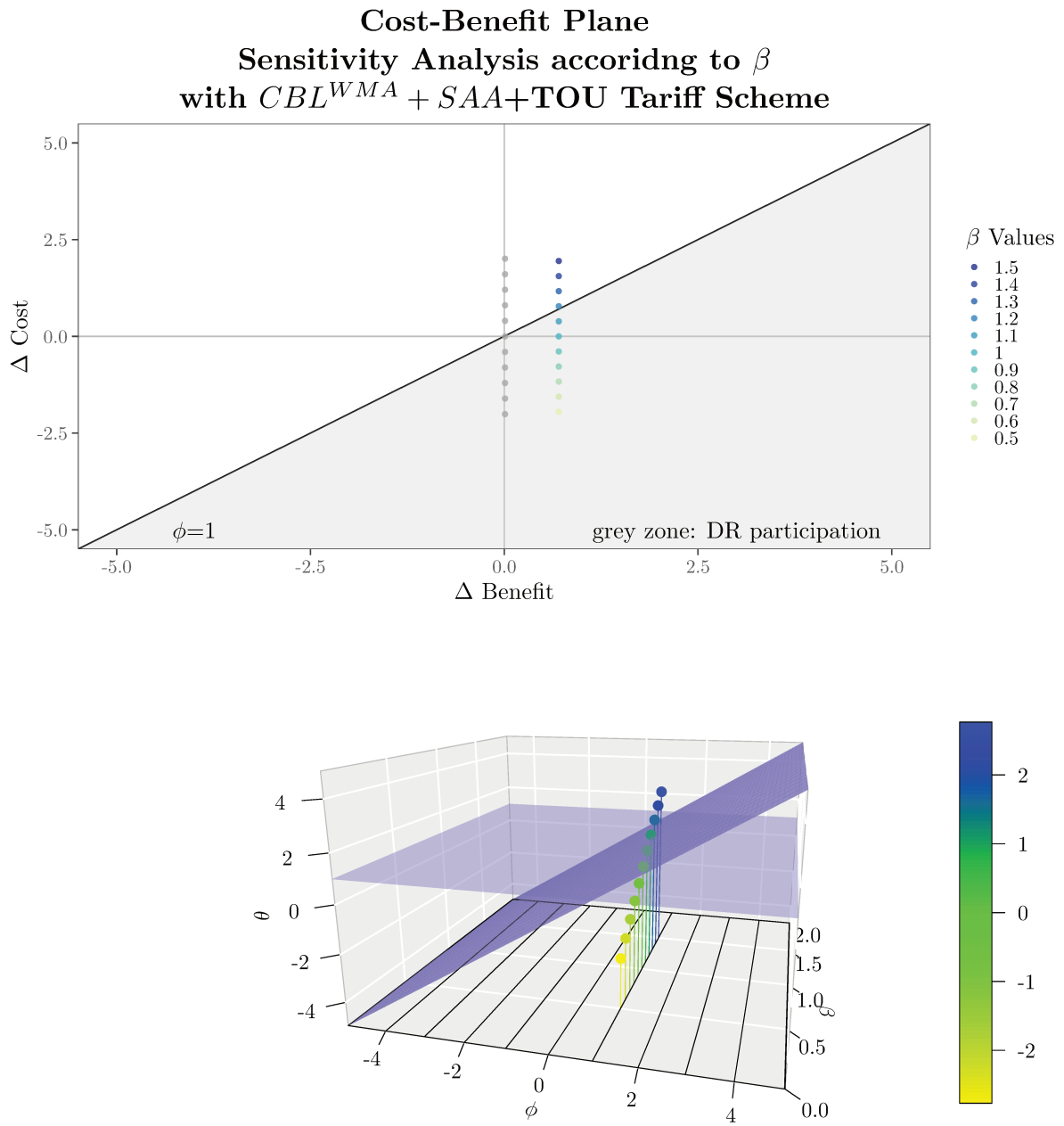


Figure 4.34: Sensitivity Analysis according to the Values of β for NEBEF (Load Shedding) with $CBL^{WMA} + SAA$ & ToU Tariff Scheme

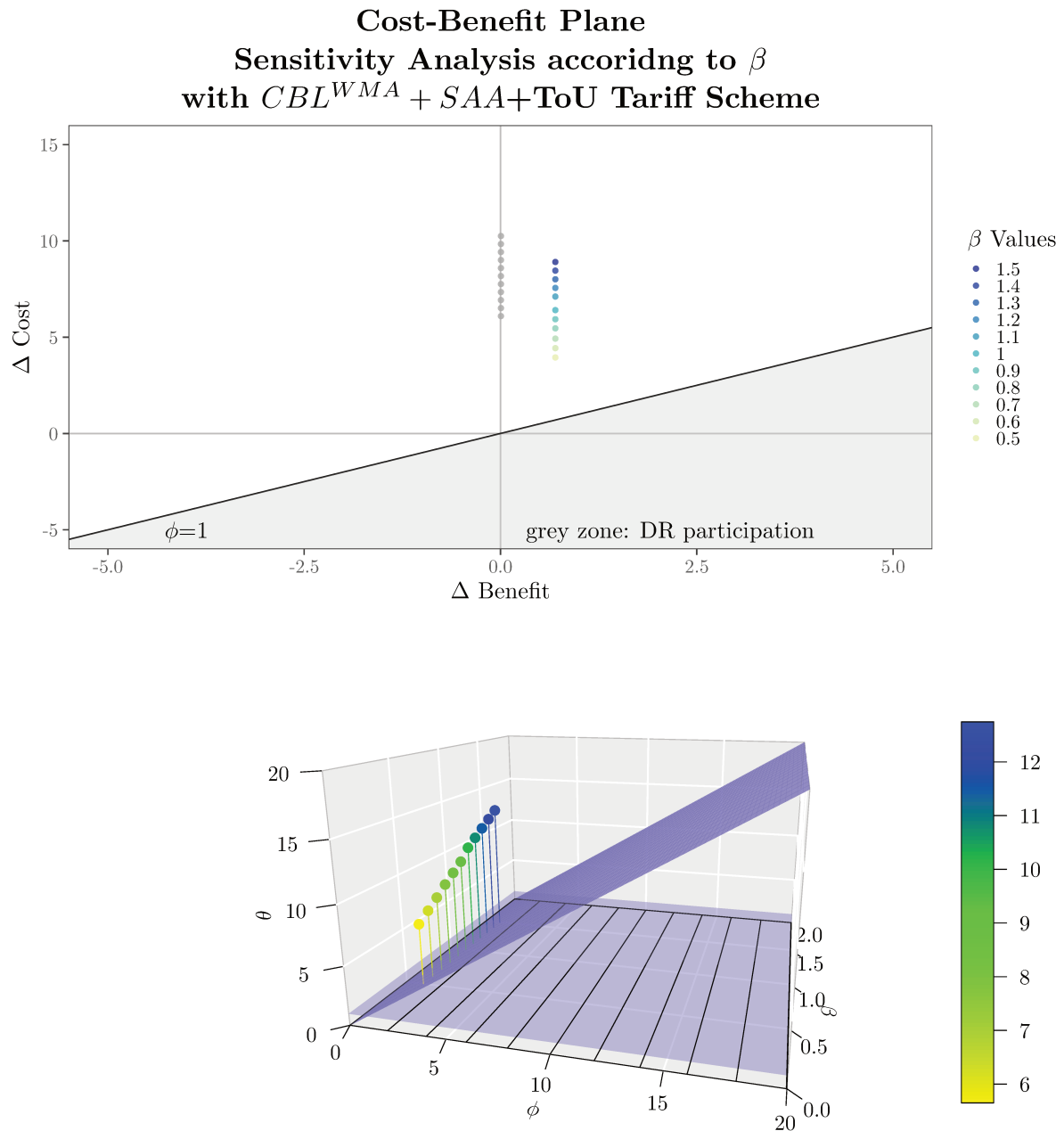


Figure 4.35: Sensitivity Analysis according to the Values of β for NEBEF (Load Shifting) with $CBL^{WMA} + SAA$ & ToU Tariff Scheme

4.5.2.5 Impacts of the Change in the Form of the Function $Coef^{INC}$

This time, I have done the SA on the impacts of the change of the inconvenience costs' functional form from linear to exponential function (Box 4.12). This change of the functional form of the inconvenience costs is relevant only for the load shifting case like South Korean DRTM, I have done this SA only for the load shifting case of French NEBEF, not for the load shedding case of French NEBEF. In Figure 4.36 all points moved downward vertically approaching to the grey DR participation zone. The reason why there was the decrease in the cost differential with the exponential function is the same with South Korean DRTM that even though

it is the exponential function, the load shifted to the very near time slots, in this case, $t = 41$ and $t = 42$, therefore, the cost increasing rate is relatively slower than that of the linear function. Even though there was the decrease in the cost differential, all points are still out of the grey DR participation zone.

Box 4.12: Assumption Changes from 'Reference Scenario': Different Form of Function $Coef^{INC}$ based on ToU Tariff Scheme (French NEBEF)

1. Target flexibility level:

- 40% $\Rightarrow r^{40}$

2. CBL estimation method:

- $CBL^{avg.10}$

3. Tariff scheme:

- ToU tariff scheme
- 0.016 cts €/Wh for peak time
- 0.01114 cts €/Wh for off-peak time

4. Inconvenience costs:

- $\beta = 0.5-1.5$, by 0.1
- linear function of $Coef^{INC}$

\Rightarrow

1. Target flexibility level:

- 40% $\Rightarrow r^{40}$

2. CBL estimation method:

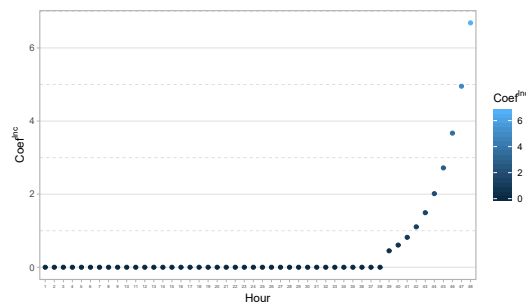
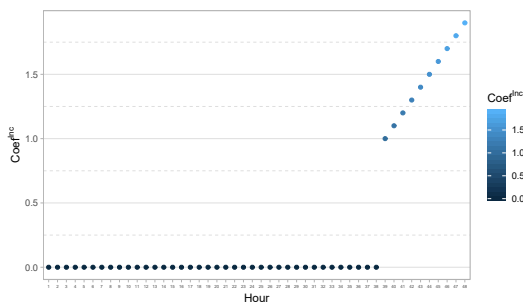
- $CBL^{avg.10}$

3. Tariff scheme:

- ToU tariff scheme
- 0.016 cts €/Wh for peak time
- 0.01114 cts €/Wh for off-peak time

4. Inconvenience costs:

- $\beta = 0.5-1.5$, by 0.1
- exponential function of $Coef^{INC}$



5. SMP:

- SMPs of DR event day (2016-01-18)

5. SMP:

- SMPs of DR event day (2016-01-18)



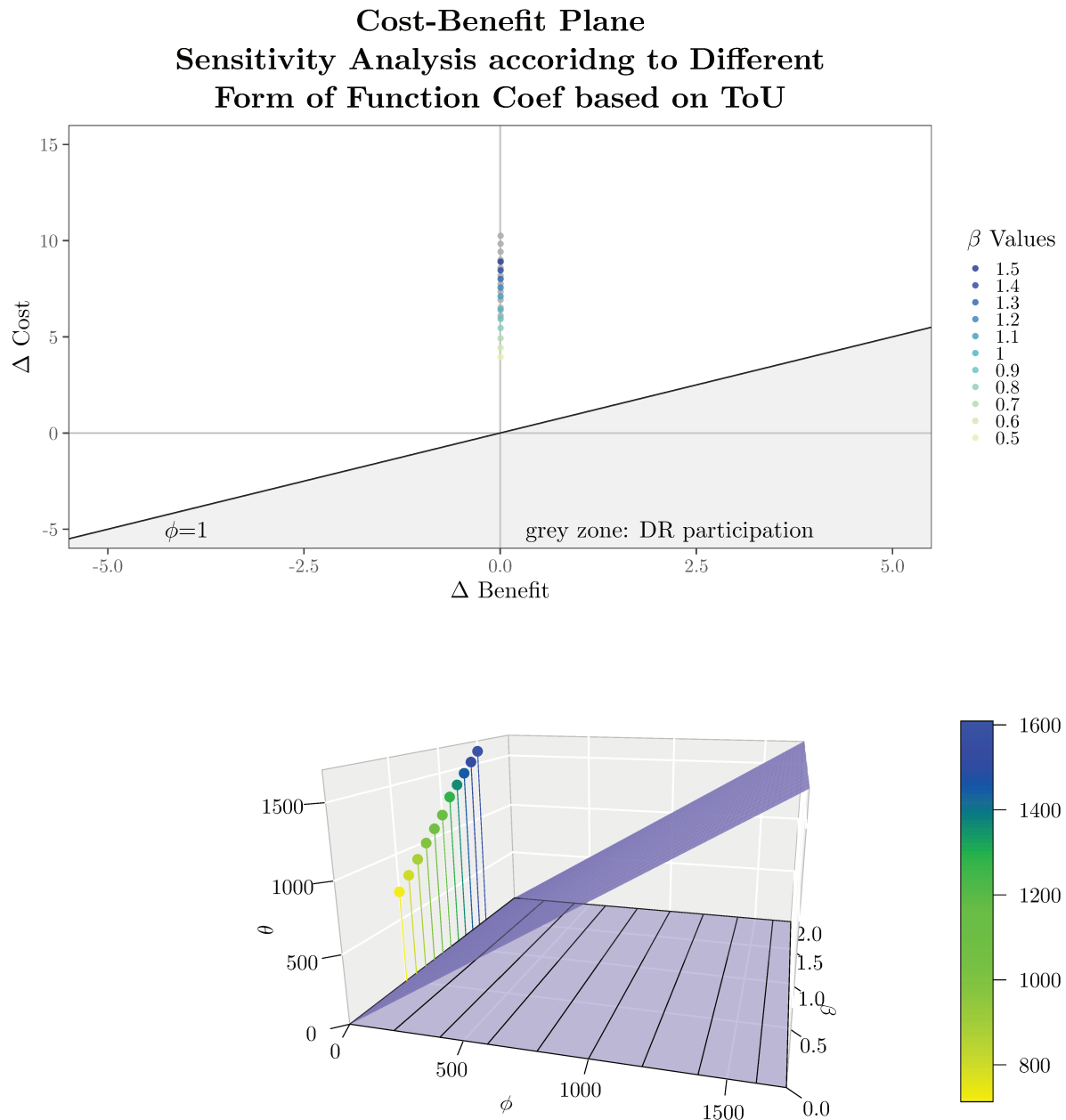


Figure 4.36: Sensitivity Analysis according to the Different Form of Function Coef^{INC} based on ToU Tariff Scheme (Load Shifting, French NEBEF)

4.5.2.6 Impacts of the Change of the SMP (Highest and Lowest)

Lastly, I have confirmed the impact of the change of the SMPs with the highest and lowest SMPs in 2016 based on the more accurate CBL estimation method ($\text{CBL}^{\text{WMA}} + \text{SAA}$) (Box 4.13 and Fig. 4.37). With the highest SMPs, there were very significant impacts shifting the points to the right horizontally both for load shedding (Fig 4.38) and load shifting (Fig 4.41) cases. As a result, all points are now in the grey DR participation zone. With the lowest SMPs, there were also significant impacts shifting the points to the left horizontally both for load shedding (Fig 4.39) and load shifting (Fig 4.42) cases. Table 4.11 summarizes all the results of SAs according

to each key parameter change.

Box 4.13: Assumption Changes from 'Reference Scenario': Highest & Lowest SMPs (French NEBEF)

<p>1. Target flexibility level:</p> <ul style="list-style-type: none"> • 40% $\Rightarrow r^{40}$ <p>2. CBL estimation method:</p> <ul style="list-style-type: none"> • $CBL^{WMA} + SAA$ <p>3. Tariff scheme:</p> <ul style="list-style-type: none"> • uniform tariff scheme • 0.01648 cts €/Wh, $p^u = c = 0.01648$, $t \in T = \{1, 2, \dots, 48\}$ <p>4. Inconvenience costs:</p> <ul style="list-style-type: none"> • $\beta = 0.5-1.5$, by 0.1 <p>5. SMP:</p> <ul style="list-style-type: none"> • SMPs of DR event day (2016-01-18) 	\Rightarrow	<p>1. Target flexibility level:</p> <ul style="list-style-type: none"> • 40% $\Rightarrow r^{40}$ <p>2. CBL estimation method:</p> <ul style="list-style-type: none"> • $CBL^{WMA} + SAA$ <p>3. Tariff scheme:</p> <ul style="list-style-type: none"> • uniform tariff scheme • 0.01648 cts €/Wh, $p^u = c = 0.01648$, $t \in T = \{1, 2, \dots, 48\}$ <p>4. Inconvenience costs:</p> <ul style="list-style-type: none"> • $\beta = 0.5-1.5$, by 0.1 <p>5. SMP:</p> <ul style="list-style-type: none"> • Highest SMPs (2016-11-07) • Lowest SMPs (2016-05-29)
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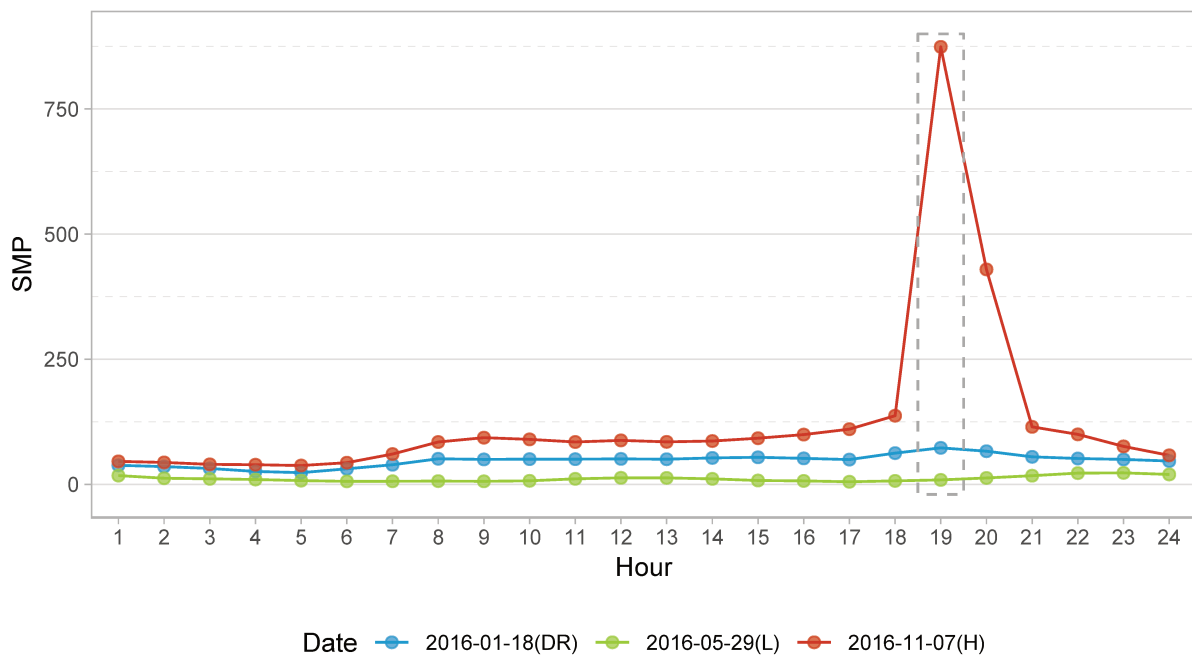


Figure 4.37: Highest & Lowest SMPs, France in 2016 (EUR(€)/MWh)

Source: "Prices - EPEX Spot Market Auction - France", EPEX, [On-line], Available: http://www.epexspot.com/fr/donnees_de_marche

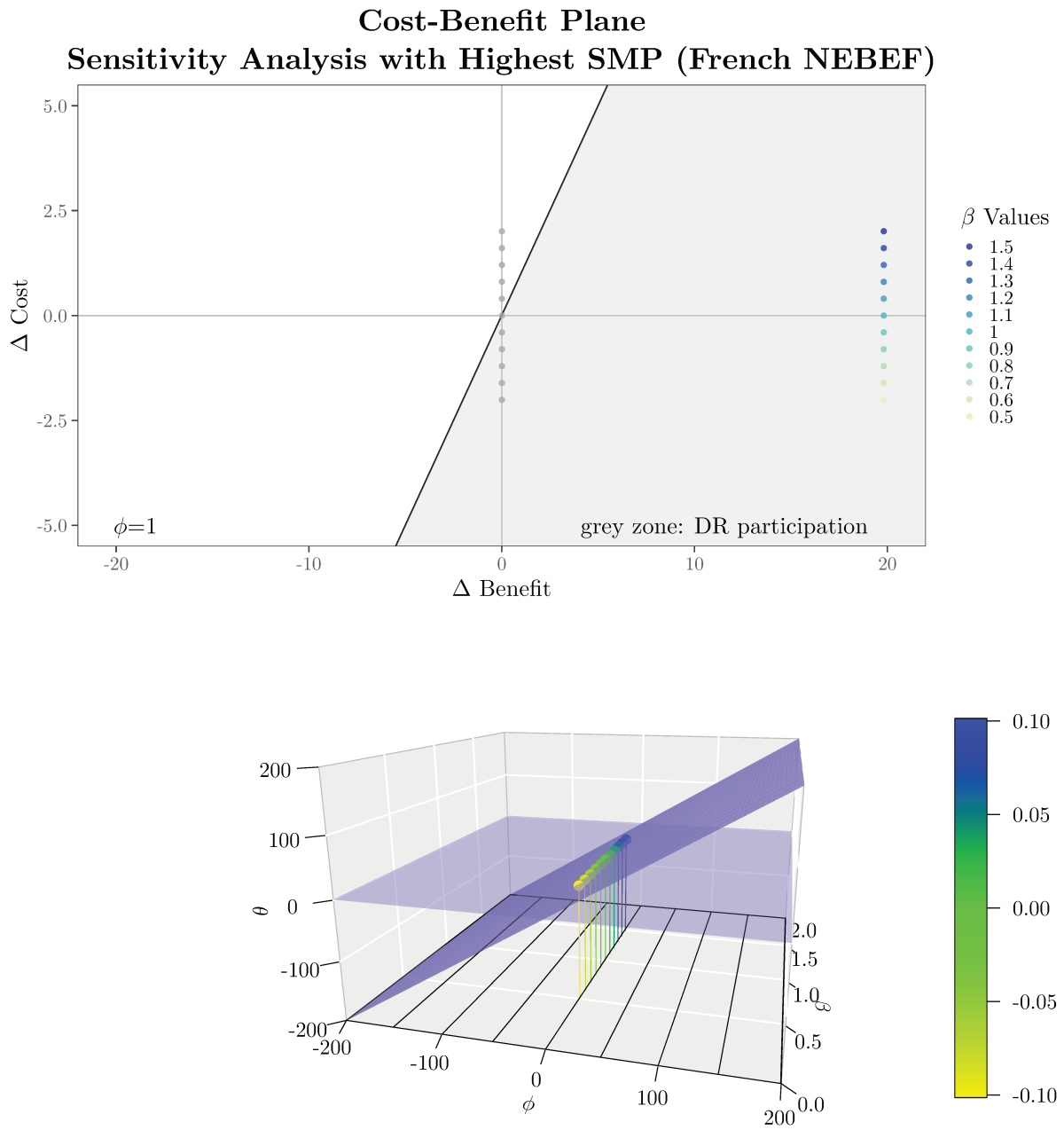


Figure 4.38: Sensitivity Analysis according to the Change of SMPs (Highest, Load Shedding, French NEBEF)

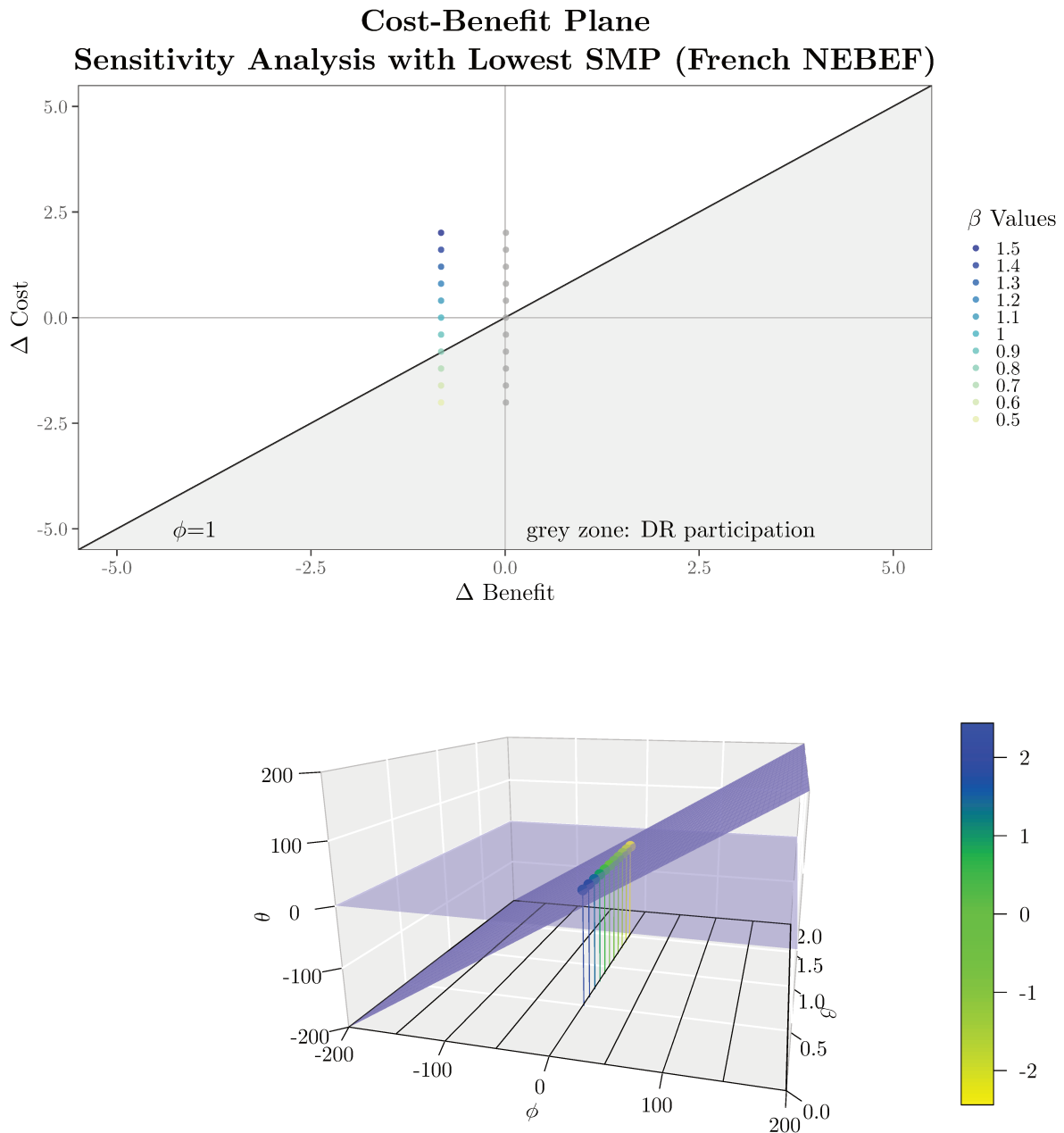


Figure 4.39: Sensitivity Analysis according to the Change of SMPs (Lowest, Load Shedding, French NEBEF)

The following Figure 4.40 illustrates the SMP that makes the net benefit 0, zero, for each β value in the case of load shedding, French NEBEF. In more detail, for example, for a participant who has a value of $\beta = 0.5$ and if we assume negative prices, the SMP should be more than -40.61 €/MWh in order to have positive or zero net benefit. For those who have a value of $\beta = 0.5, 0.6, 0.7$, the thresholds are negative, so as long as the SMPs are positive (above the dash and dot line in red), there will be positive net benefits for them. Likewise, for a participant who has a value of $\beta = 1.5$, the SMP should be more than 127.77 €/MWh in order to have a positive or zero net benefit. For your reference, the SMP for $t = 37$ and $t = 38$ on January 18, 2016, it was 73.07 €/MWh —the dash and dot line in green.

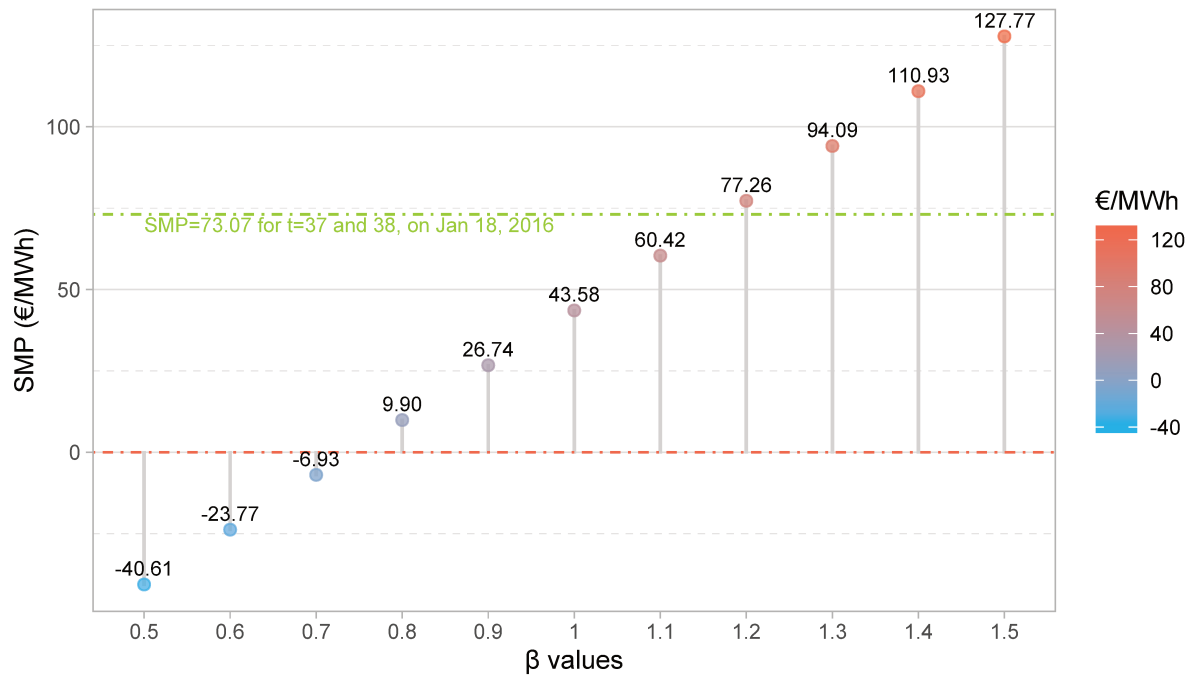


Figure 4.40: Threshold SMP of Net Benefit for Each β Value (Load Shedding, French NEBEF, €/MWh)

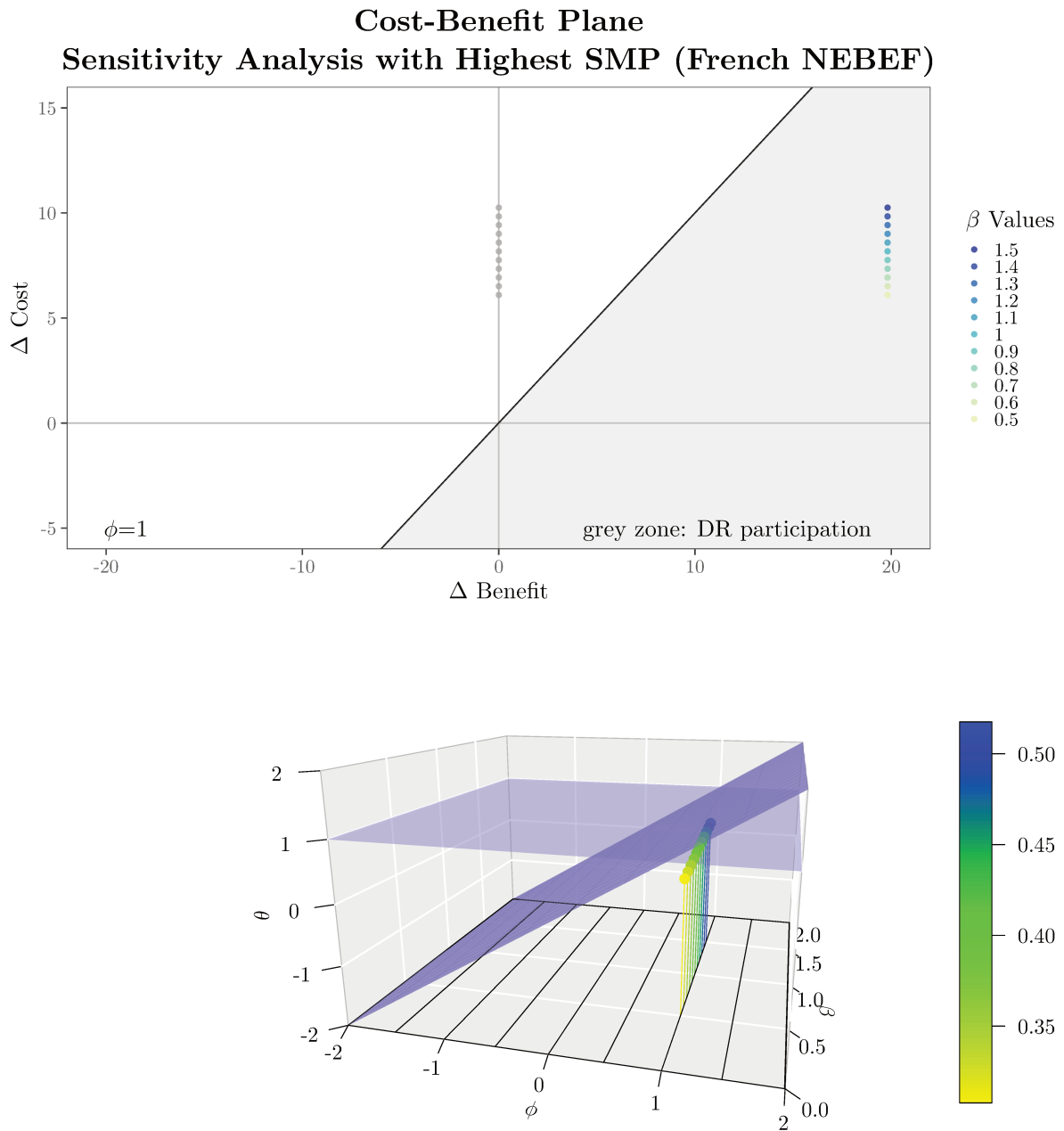


Figure 4.41: Sensitivity Analysis according to the Change of SMPs (Highest, Load Shifting, French NEBEF)

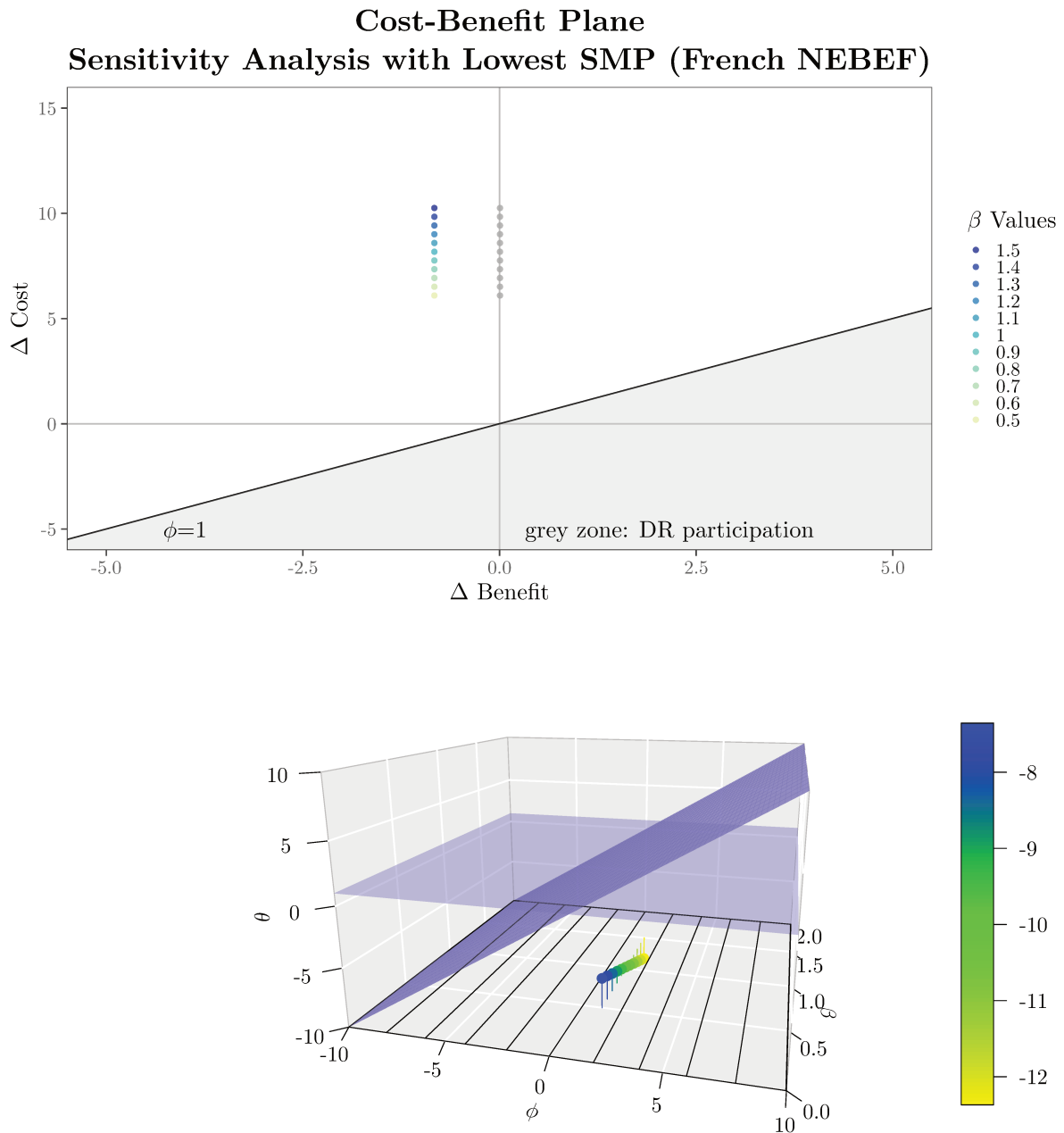


Figure 4.42: Sensitivity Analysis according to the Change of SMPs (Lowest, Load Shifting, French NEBEF)

The following Figure 4.43 illustrates the SMP that makes the net benefit 0, zero, for each β value in the case of load shedding, French NEBEF. In more detail, for example, for a participant who has a value of $\beta = 0.5$, the SMP should be more than 299.07 €/MWh in order to have positive or zero net benefit. Likewise, for a participant who has a value of $\beta = 1.5$, the SMP should be more than 473.29 €/MWh in order to have a positive or zero net benefit. For your reference, again, the SMP for $t = 37$ and $t = 38$ on January 18, 2016, it was 73.07 €/MWh—the dash and dot line in green.

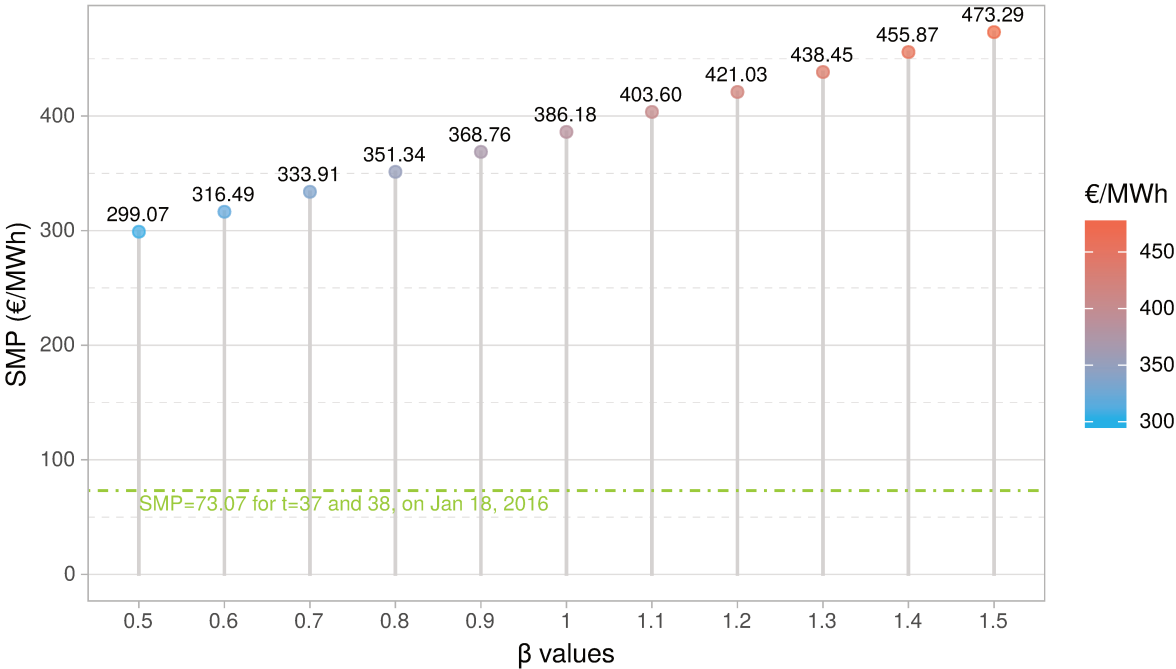


Figure 4.43: Threshold SMP of Net Benefit for Each β Value (Load Shifting, French NEBEF, €/MWh)

Table 4.11: Summary for Results of Sensitivity Analyses

parameters	South Korea	France
β : 0.5 \Rightarrow 0.5-1.5 by 0.1	Significant impacts: β values between 0.6-1.5, out of DR participation zone, upward vertical shifts	Load shedding: significant impacts: β values between 1.1-1.5, out of DR participation zone, upward vertical shifts Load shifting: significant impacts: all points are out of DR participation zone, upward vertical shifts
Accurate CBL	No need for this SA for South Korea	Load shedding: significant impacts: β value of 1.1 moved into DR participation zone, rightward horizontal shifts Load shifting: significant impacts: but all points are still out of DR participation zone, rightward horizontal shifts
Tariff Scheme: Uniform \Rightarrow ToU	Small impacts: β 0.6 moved into DR participation zone, downward vertical shifts	Load shedding: tiny impacts: subtle vertical shifts Load shifting: small impacts: vertical shifts
ToU based on accurate CBL	No need for this SA for South Korea	Load shedding: same with SA with accurate CBL Load shifting: same with SA with more CBL, but a little bit diagonal shifts
Coef^{INC} based on ToU: linear \Rightarrow exponential	Large impacts: all points moved into DR participation zone, downward vertical shifts	Load shifting: small impacts: all points are still out of DR participation zone, downward vertical shifts
Different SMPs based on accurate CBL: highest & lowest SMPs	Large impacts: •highest SMPs: β values of 0.6-0.8 moved into DR participation zone, rightward horizontal shifts •lowest SMPs: all points are out of DR participation zone, leftward horizontal shifts	Load shedding: •highest SMPs: very significant impacts: all points are in DR participation zone, rightward horizontal shifts •lowest SMPs: significant impacts: β values of 0.8-1.0 went out of DR participation zone, leftward horizontal shifts Load shifting: •highest SMPs: very significant impacts: all points are in DR participation zone, rightward horizontal shifts •lowest SMPs: significant impacts: all points are out of DR participation zone, leftward horizontal shifts

4.6 Conclusion

In this Chapter 4, we have conducted CBAs, Decision-making analyses, and SAs based on the CBLs established in the previous Chapter 3. While constructing the CBA model, we could mathematically and systematically reconfirm the importance of accurate CBL estimation methods. This is in line with the result of the previous study on the CBL estimation methods in Chapter 3. If the CBL estimation methods are inaccurate, then the actually reduced loads of a residential client will be underestimated, and the amount of the remuneration will decrease. In the end, this will discourage the DR participation of the residential client. That point was also observed in the SAs for the French NEBEF case in which the CBL estimation method was changed to the CBL estimation method utilized in South Korea. With the inaccurate CBL estimation method $CBL^{avg.10}$, there were too tiny net benefits, but with the accurate CBL estimation method $CBL^{WMA} + SAA$, we observed the significant and positive horizontal shift with increased net benefits. From the DR system operator's perspective, the accurate CBL estimation method could prevent the intentional and malicious CBL manipulation of the DR participants—strategic countervailing incentives. Moreover, of course, only if CBLs are well-defined, the optimality of the DR program could be guaranteed. Therefore, the CBL estimation method can play a significant role in the decision-making of the DR participation, and the transparent and sustainable operation.

Moreover, we were able to figure out the importance of the degrees of the additional inconvenience (coefficient β) both for load shedding and load shifting in the CBAs and the SAs. In the CBA for the South Korean case, the residential client shifted the required load reduction to just before and after the DR event time slots.^[20] It was the result of the optimization of the costs (linear programming) taking into account the additional inconvenience costs. Furthermore, in the SAs both for the South Korean and French case in which the impacts of the change in the β value were examined, as the β value increases, the costs increase, and as a result, one residential client ends up to decide not to participate in the DR program—or go much further if it was not in the DR participation area at the beginning. This result provides us with a meaningful policy implication that when a DR system operator designs the DR market, it needs to carefully consider one customer's objective or subjective different additional inconvenience costs or perceptions on it for load shedding and load shifting.

We could also observe that there was a very slight vertical shift with the change of the tariff scheme. It means that if there is a very small difference between the prices of peak and off-peak periods, which means a small peak/off-peak ratio of ToU tariff scheme, there would not be significant motivations for a residential client to participate in the DR program—especially, price-based DR programs. Therefore, if a DR system operator would like to promote a DR program with an implicit tariff scheme of ToU, there should be a stark pricing differentiation between the peak and off-peak period. SAs with different peak/off-peak ratios of ToU tariff schemes will be very relevant to the design of the ToU tariff scheme for the residential sector in South Korea.

Like the importance of the coefficient β , the importance of the functional form of $Coef^{INC}$ was confirmed. Whether one participant's functional form of $Coef^{INC}$ is linear or exponential has the impacts on the costs, and, in turn, it could change the decision to which time slot the participant will shift the load reductions in order to minimize the additional inconvenience costs.

We have also witnessed the very significant impacts of SMP with the highest and lowest SMPs. It is very natural and in accordance with the intrinsic objective of DR—when there is peak demand, SMP is high, and it gives clients greater motivation to participate in the DR program. As a result, it can reduce the peak demand, and achieve the reliability with this flexibility. This is a very important point that because the benefit for the participants is the function of SMP, even if it is the uniform tariff scheme, DR participation plays a role

^[20] As a result of the cost optimization and the shifted loads, there would be rebound effects for the time slots before or after the DR event time. It means the possibility of another peak load due to rebound effects just before or after the DR event. Therefore, it could lead to higher prices for these periods again and cause another gaming situation on the market. It depends on the size of the aggregated load shifts and the relative difference between loads of the time slots before or after the DR event and loads of the DR event time. This issue is very interesting and will be a good subject for the following research in the near future.

as a link between the wholesale market and the retail market. The uniform tariff scheme cannot send the true signal on the marginal costs for electricity supply, however, the DR participants can receive the price information as they participate in the DR mechanism. Therefore, DR can correct the distorted market signal and increase the efficiency of the power system.

On top of the SAs with the highest and lowest SMPs, we have also calculated the threshold SMPs in order for a residential participant to have positive or equal to zero net benefits according to each β value. From the residential customer's perspective, these threshold SMPs can be the criteria whether or not to participate in the DR program. As a consequence, for LAs and DR system operators, these threshold SMPs can give them the information when they expect the participation rates for a specific time slot with a specific SMP and a residential customer with a specific β value.

In addition to SMP itself, as we compare the two different DR mechanisms of South Korea and France, the importance of the appropriate level of remuneration has been highlighted. Unlike the South Korean case, in the French NEBEF mechanism, some part, that is 'Versement' v (transfer or sourcing cost payments), of the SMP should be transferred to the electricity supplier, so the final remuneration for a residential client is too negligible to encourage them to participate in the DR program. The question, "What is the ideal level for the DR remuneration?", is an issue that needs another thorough research, and it seems that *a priori* the French case is more close to the theoretically ideal DR remuneration level, but the South Korean case is more encouraging for the potential DR participants. Therefore, the French DR operator, RTE, could take into consideration the DR remuneration level for the sustainable DR program.

Even though the CBA is absolutely imperative for a DR program, and the constructed CBA model in this study is quite simple, there was no this kind of fundamental model and research so far. Making good use of the explicit and simple mathematical model of linear algebra renders the ambiguous DR mechanism simple and clear. With this simple mathematical model, it was possible to figure out clearly the interactions among a series of components of a DR mechanism, such as CBL, Maximum Reducible Capacity, required load reduction, actually fulfilled load reduction, SMP, tariff scheme, load shedding and load shifting, additional inconvenience costs, and so forth.

The art of this simple model is placed on the fact that the process of the analysis is continuous from the very beginning of the CBL estimation, CBA, Decision-making Analysis, and then finally to the SA with quite consistent concepts and elements. Therefore, this entire model provides a package for the analysis of a DR mechanism. The model used in this study is also quite generic which means that it can be applied to other industrial or commercial DR programs, or in other countries where the system operators consider introducing DR programs.

In this research, since we have focused on the peak demand and the potential of DR to reduce the peak demand, we have assumed that the DR event periods are given. However, it is not always the case. In the Economic DR program in South Korean DRTM and French NEBEF, LAs, on behalf of the participants, can bid demand-side resources any time they want if it is profitable for them and their customers. Their decision-making to which time slot they will bid can also be dealt with the optimization of the costs (linear programming) internally. For the Peak Reduction DR program in South Korean DRTM, the CBA model used in this study is sufficient, but for the Economic DR program in South Korean DRTM and French NEBEF, it needs this kind of expansion of the CBA model.

In a similar context, in these CBAs, I chose the peak days for the DR event day both for the South Korean and French cases. However, let alone the SAs, in order to reinforce the robustness of the results of the CBA and Decision-making analysis, it would be a good idea to conduct the same CBA and Decision-making Analysis of the other periods in a year that have quite different load profiles, at the same time, by making more use of Monte Carlo simulation methods—it would not change the results much, though. This kind of improvement should be realized in the next research opportunity.

§Chapter 5

Conclusions and Implications

We have begun this research observing the reality in which we needed to come up with alternatives to address the issues of reliability, flexibility, efficiency, security of electricity supply, GHG emissions, climate change, integration of RESs in Chapter 1 and 2. The theoretical rationale proved that DR can efficiently deal with those concerns. The essentials of the theoretical rationale are that DR can reduce physical loads, especially during peak demand periods, and that it has impacts on the elasticity of the electricity demand curve. Actually, almost all those DR's benefits—enhancing reliability, providing flexibility, increasing efficiency of the power system, ensuring security of supply, decreasing the electricity price, reducing GHG emissions, preventing climate change, helping integration of RESs—in the literature review in Chapter 1 derive from these essentials of DR.

Looking at the background and literature review including definitions, categorizations, advantages and challenges in Chapter 1 provided us with the orientation of this research that we focus on DR, in particular market-oriented, explicit, incentive-based DR programs for residential customers. In addition, in the literature review, we have found that the technical issues are not the critical hindrance anymore, but we need more studies on the accurate CBL estimation methods, appropriate CBAs, better market designs, and well-prepared regulations for DR.

The case study of the U.S. in Chapter 2 was worthy of attention because, at the moment, the U.S. is the leading country with regard to the performance of DSM and DR, and its case study could give some ideas for the other cases, like France and South Korea, whenever they face to problems or would like to improve their DR market designs. Because this research's main target countries are France and South Korea, the case of the U.S. was not thoroughly addressed, so it is one of the limitations of this research. In the following research, more detailed and state-specific studies, such as New England, New York, California, PJM regions, Texas, and so forth, are needed for the DR mechanisms in the U.S.

Although DR has a clear theoretical rationale and a variety of advantages, the specific motivations to promote market-oriented DR programs were different between France and South Korea. France needed measures to decrease the price on the wholesale market or decrease the expensive imports, and to enhance the reliability during the peak periods. Moreover, for the energy transition, DR is necessary to better integrate the increasing RESs providing more flexibility. For South Korea, it is expected that DR will be helpful to ensure the reliability of the power system and security of supply. As the South Korean government would like to phase out the nuclear power plants and decrease the share of fossil fuel-based power plants, it is losing more options from the supply-side and needs to place more emphasis on DSM and DR.

The detailed case studies of France and South Korea and the comparisons of the electricity markets, DR mechanisms in Chapter 2 were imperative to figure out the fundamental information and specifications for the following analyses in Chapter 3 and 4. As we have looked at the evolutions of the French NEBEF mechanism and South Korea's DRTM, we were able to figure out their patterns and characteristics of the performance. Thanks to that, we could narrow down the scope of the research and pinpoint the specific target of the research in terms of the market, season, date, time, and sector.

Based on the fundamental information and specifications for France's NEBEF mechanism and South Korea's

DRTM in Chapter 2, we have tried to find out more accurate CBL estimation methods. It was necessary for the following CBAs, Decision-making analyses, and SAs. In addition, it was important itself to find out better methods for CBL estimation because it is linked to the ultimate remuneration, and therefore, to the motivations for the residential customers to participate in the DR programs.

As a result of the study in Chapter 3, we have found that the CBL estimation methods of South Korean DRTM, especially the two CBL methods of $CBL^{WMA} \cdot PAC$ and $CBL^{WMA} + SAA$, perform surprisingly very well with extremely low error rates about 0.5% while all the CBL estimation methods of NEBEF do not perform very well with high error rates about 12%–25%. In addition, when we applied the two CBL estimation methods of $CBL^{WMA} \cdot PAC$ and $CBL^{WMA} + SAA$ to the rescaled French average household load profile to establish the CBL, it resulted in a high performance with extremely low error rates less than 0.5% again.

Furthermore, the results of the supplementary analyses of the different load profiles of different seasons are in line with the main results reconfirming that the two CBL estimation methods with adjustment ($CBL^{WMA} \cdot PAC$ and $CBL^{WMA} + SAA$) are the best even if load profiles are more stochastic and volatile. Therefore, this cross-validation between different seasons in a country added the robustness of the research. With the results, this study provides a country, in particular, France, with a meaningful policy implication to ameliorate the CBL estimation methods of NEBEF and ultimately the DR market design.

Like South Korean DRTM, the NEBEF mechanism is a quite recent market-oriented mechanism of DSM, so it is still evolving since the 'Règles NEBEF 1' in 2013. Even though it seems that RTE has tested many possible CBL estimation methods since the experimental phase, for example, the panel data analysis approach, it appears that RTE has not yet explicitly suggested or introduced the alternative options like PAC and SAA. According to the results of this research, the low performance and high error rates of the CBL estimation methods of NEBEF derived from the fact that it only relies on the simple average and median and does not use any adjustment options which could capture the recent changes of the load profile caused by whatever it is a temperature-based or socio-economic-based stochastic event.

As we have looked at the developing trends of both the South Korean and French DR mechanisms in terms of the volume and frequency, the importance of the NEBEF mechanism will be more significant with more intermittent RESs, the concern on climate change, sustainability, and security of electricity supply. In order to exploit the full-fledged DR mechanism in France, we need to pay more attention to the importance of the accurate CBL estimation methods which are the fundamental elements to encourage potential participants. As we have observed, the currently utilized CBL estimation methods are likely to result in the underestimation of the CBLs, in turn, results in that the actual efforts or reductions will be underappreciated than it is. These inaccurate CBL methods could undermine the French NEBEF mechanism despite its advantage such as the high-level openness of all the markets for the demand-side resources.

Furthermore, it is expected that the accurate CBL estimation methods can prevent the participants from intentional and malicious manipulation of their CBLs. It is quite an important point from the DR system operator's or LA's perspective. If the CBL estimation methods are very accurate, then there will be little room for participants to strategically manipulate their CBLs in order to get remunerated much more than it should be. Only with these well-defined CBL estimation methods which can avoid the underestimation or overestimation as measurement error and the strategic countervailing incentives, the optimality of DR programs can be guaranteed.

Considering the above-mentioned policy implications, this study provides a good opportunity to shed light on and to compare the CBL estimation methods of South Korea and France each other. It is rare to see this kind of comparative analysis between countries focusing on the CBL estimation methods in practice. One of the difficulties to conduct this kind of research is that it is not easy to obtain the real-time load profiles of an individual level household due to the issues of privacy or information access. The approach in which we have used the rescaled load profile from the aggregate national loads enabled this analysis. The very clear and distinct terms and simple but detailed equations and explanations will be helpful for further studies on CBLs in many countries which are actively developing DR mechanisms.

On top of that, the estimated CBLs played a role as a stepping stone or foundation for the further analysis such

as the Decision-making Analysis based on CBA and SA. Without this part on CBLs, it will be almost impossible to proceed to further research or will face the ambiguity of DR mechanism. Only based on the accurately estimated CBLs, the actual load reduction, optimal remuneration level, marginal disutility for participants with load shedding and load shifting, behavioral change of the participants (electricity consumption pattern with DR), the effectiveness of ToU tariff scheme, and so forth can be addressed in an appropriate way.

In Chapter 4, while constructing the CBA model, we could mathematically and systematically reconfirm the importance of accurate CBL estimation methods. It was also observed in the SAs for the French NEBEF case in which the CBL estimation method was changed to the CBL estimation method utilized in South Korea. With the inaccurate CBL estimation method CBL^{avg-10} , there were too tiny net benefits, but with the accurate CBL estimation method $CBL^{WMA} + SAA$ we observed the significant and positive horizontal shift with increased net benefits. Therefore, the CBL estimation method can play a significant role in the decision-making of the DR participation, and the transparent and sustainable operation.

Moreover, we were able to figure out the importance of the degrees of the additional inconvenience (coefficient β) both for load shedding and load shifting in the CBAs and the SAs. In the CBA for the South Korean case, the residential client shifted the required load reduction to just before and after the DR event time slots—the similar pattern has also been confirmed for the French NEBEF load shifting case in which load reductions have been shifted to just after the DR event. It was the result of the optimization of the costs (linear programming) taking into account the additional inconvenience costs. Furthermore, in the SAs both for the South Korean and French case in which the impacts of the change in the β value were examined, as the β value increases, the costs increase, and as a result, one residential client ends up to decide not to participate in the DR program—or go much further if it was not in the DR participation area at the very beginning. This result provides us with a meaningful policy implication that when a DR system operator designs the DR market, it needs to carefully consider one customer's objective or subjective different additional inconvenience costs or perceptions on it for load shedding and load shifting.

We could also observe that there was a very slight vertical shift with the change of the tariff scheme. It means that if there is a very small difference between the prices of peak and off-peak periods, there would not be significant motivations for a residential client to participate in the DR program. Therefore, if a DR system operator would like to promote a DR program with an implicit tariff scheme of ToU, there should be a stark pricing differentiation between the peak and off-peak period.

Like the importance of the coefficient β , the importance of the functional form of $Coef^{INC}$ was confirmed. Whether one participant's functional form of $Coef^{INC}$ is linear or exponential has the impacts on the costs, and, in turn, it could change the decision to which time slot the participant will shift the load reductions to minimize the additional inconvenience costs.

We have also witnessed the very significant impacts of SMP with the highest and lowest SMPs. It is very natural and in accordance with the intrinsic objective of DR—when there is peak demand, SMP is high, and it gives clients greater motivation to participate in the DR program. As a result, it can reduce the peak demand, and achieve the reliability with this flexibility. This is a very important point that because the benefit for the participants is the function of SMP, even if it is the uniform tariff scheme, DR participation plays a role as a link between the wholesale market and the retail market. The uniform tariff scheme cannot send the true signal on the marginal costs for electricity supply, however, the DR participants can receive the price information as they participate in the DR mechanism. Therefore, DR can correct the distorted market signal and increase the efficiency of the power system.

Moreover, the threshold SMPs calculated have more clarified the boundary between participation and non-participation for a residential customer with a specific β value. These threshold SMPs could provide us, especially for LAs and DR system operators, with valuable information on the expectation of the participation for a specific time slot with a specific SMP. The detailed information on the threshold SMPs will reduce the uncertainty around the net benefit and, as a result, will increase motivations to participate.

In addition to SMP itself, as we compare the two different DR mechanisms of South Korea and France, the importance of the appropriate level of remuneration has been highlighted. Unlike the South Korean case, in

the French NEBEF mechanism, some part, that is ‘*Versement*’ v (transfer or sourcing cost payment), of the SMP should be transferred to the electricity supplier, so the final remuneration for a residential client is too negligible to encourage them to participate in the DR program. What the ideal level for the DR remuneration is an issue that needs another in-depth research, and it seems that *a priori* the French case is more close to the theoretically ideal DR remuneration level, but the South Korean case is more encouraging for the potential DR participants. Therefore, the French DR operator RTE could take into consideration of the DR remuneration level for the sustainable DR program.

Even though the CBA is absolutely imperative for a DR program, and the constructed CBA model in this study is quite simple, there was no this kind of fundamental model and research so far. Making good use of the explicit and simple mathematical model of linear algebra renders the ambiguous DR mechanism simple and clear. With this simple mathematical model, it was possible to figure out clearly the interactions among a series of components of a DR mechanism, such as CBL, Maximum Reducible Capacity, required load reduction, actually fulfilled load reduction, SMP, tariff scheme, load shedding and load shifting, additional inconvenience costs, and so forth.

The art of this simple model is that the process of the analysis is continuous from the very beginning of the CBL estimation, CBA, Decision-making Analysis, and then finally to the SA with quite consistent concepts and elements. Therefore, this entire model provides a package for the analysis of a DR mechanism. The model used in this study is also quite generic which means that it can be applied to other industrial or commercial DR programs, or in other countries where the system operators consider introducing DR programs.

When it comes to the limitations of this study, there are several limitations to point out for the following researches although we have mentioned a few of them already. In Chapter 3, we have relied on the rescaled load profiles in order to find out more accurate CBL estimation methods and to establish the CBLs as a result. Rescaling down the national aggregate load profiles to an average household load profile, it was one method that we have come up with so as to overcome the issue of non-available data on the individual residential customer level. Therefore, it is one of the limitations of this research, and in the following study, the empirical analysis with the real data for each country, France and South Korea, should be done so as to verify the methodologies and models used in this research.

In this research, since we have focused on the peak demand and the potential of DR to reduce the peak demand, we have assumed that the DR event periods are given. However, it is not always the case. In the Economic DR program in South Korean DRTM and French NEBEF, LAs, on behalf of the participants, can bid demand-side resources any time they want if it is profitable for them and their customers. Their decision-making to which time slot they will bid can also be dealt with the optimization of the costs (linear programming) internally. For the Peak Reduction DR program in South Korean DRTM, the CBA model used in this study is sufficient, but for the Economic DR program in South Korean DRTM and French NEBEF, it needs this kind of expansion of the CBA model.

In a similar way, in those CBAs, I have chosen the peak days for the DR event day both for the South Korean and French cases. However, let alone the SAs, so as to reinforce the robustness of the results of the CBA and Decision-making analysis, it would be a good idea to conduct the same CBA and Decision-making Analysis of the other periods in a year that have quite different load profiles, at the same time, by making more use of Monte Carlo simulation methods—it would not change the results much, though. This kind of improvement should be realized in the next research opportunity.

Even though we have highlighted the difference in the compensation levels between South Korean DRTM and French NEBEF and confirmed the importance of the remuneration level to promote participation, a more detailed study should be done about it and related concepts like NBT and NBTP that I have simply mentioned in Chapter 2.

While I have been conducting this research, the two DR programs in South Korea and France were very new-born mechanisms, and there were not so many datasets available. However, as time goes by, there are more datasets available for the public and researchers such as bidding information of demand-side resources in DR markets. Therefore, it will be needed to analyze the bidding datasets in more detail.

Furthermore, we could not deal with other issues relevant to DR, such as the energy storage system, electric vehicles, supply-side resources, and so forth, because this study focused only on DR. The interactions and relationships between DR and those other resources, for example, an analysis of how DR can be helpful for the better integration of RESs to the power system, would be good subjects for the following researches. In this research, it was the top-down approach, for example considering the national aggregate load profile and from the perspective of the DR system operator. For the following research, a bottom-up approach could be a good alternative taking into account DR program participant's heterogeneity, behavior, and technology innovations.

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Appendix A: Supplementary Figures & Tables

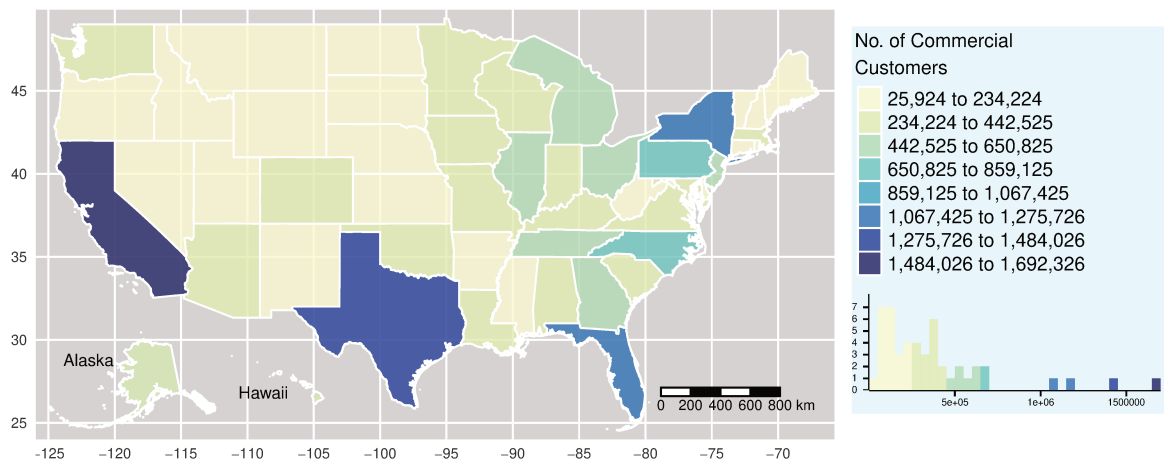


Figure A.1: The Number of Commercial Customers by State, 2016 in the U.S.

Source: *Annual Electric Power Industry Report*, by U.S. Energy Information Administration.; "Electric power sales, revenue, and energy efficiency Form EIA-861 detailed data files", U.S. Energy Information Administration, [On-line], Available: <https://www.eia.gov/electricity/data/eia861/>

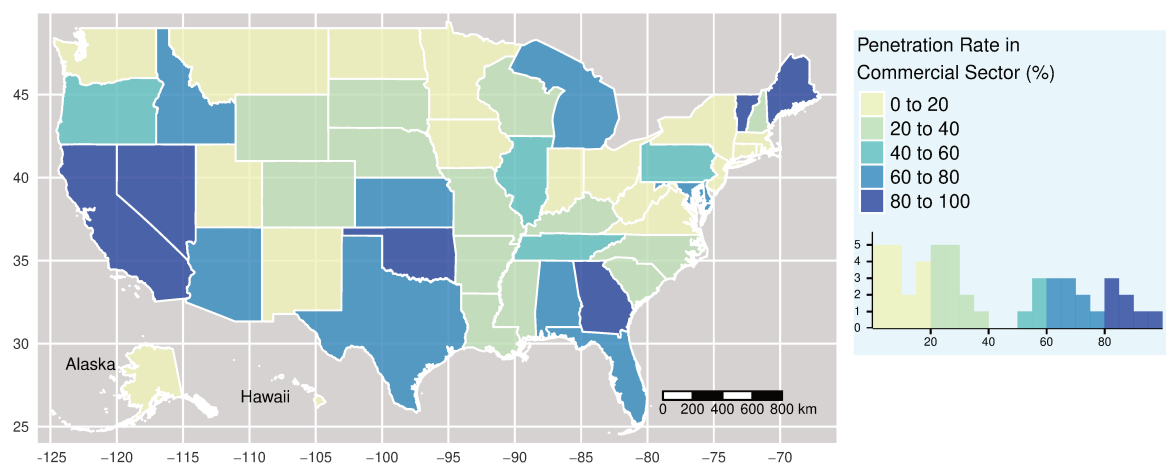


Figure A.2: Commercial Smart Meter Adoption Rates by State, 2016 in the U.S.

Source: *Annual Electric Power Industry Report*, by U.S. Energy Information Administration.; "Electric power sales, revenue, and energy efficiency Form EIA-861 detailed data files". U.S. Energy Information Administration, [On-line], Available: <https://www.eia.gov/electricity/data/eia861/>

Table A.1: The Top 10 States in terms of the Number of Customers and AMI Penetration Rate in the Commercial Sector

Rank	State	No. of Customers	State	AMI Penetration Rate (%)
1	California	1,692,326	District of Columbia	95.7
2	Texas	1,447,247	Nevada	93.5
3	Florida	1,199,897	Georgia	86.9
4	New York	1,072,896	Maine	86.0
5	Pennsylvania	696,080	Vermont	84.5
6	North Carolina	672,610	California	81.6
7	Ohio	623,730	Oklahoma	81.1
8	Illinois	606,954	Arizona	77.8
9	Georgia	567,431	Texas	74.6
10	Michigan	538,677	Idaho	71.9

Source: *Annual Electric Power Industry Report*, by U.S. Energy Information Administration.; "Electric power sales, revenue, and energy efficiency Form EIA-861 detailed data files". U.S. Energy Information Administration, [On-line], Available: <https://www.eia.gov/electricity/data/eia861/>

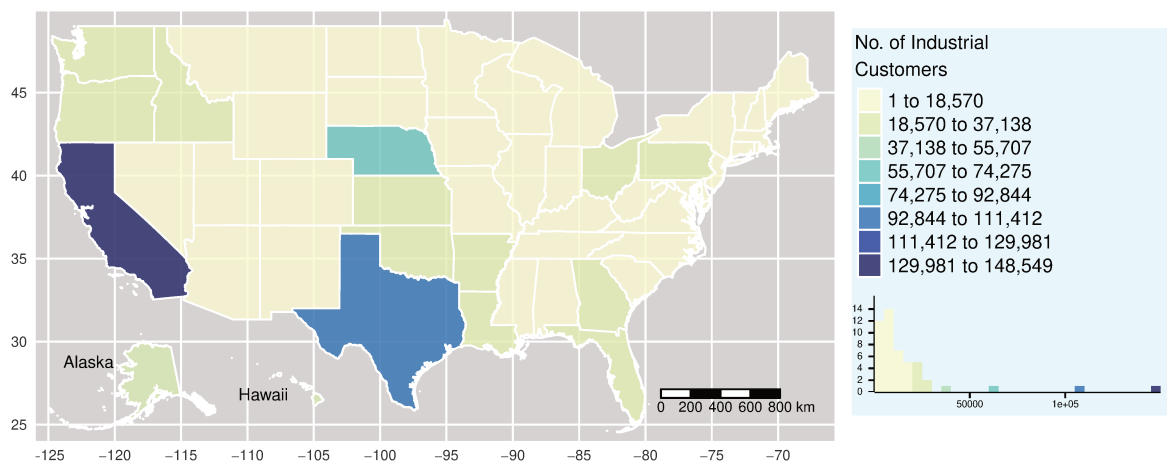


Figure A.3: The Number of Industrial Customers by State, 2016 in the U.S.

Source: *Annual Electric Power Industry Report*, by U.S. Energy Information Administration.; “Electric power sales, revenue, and energy efficiency Form EIA-861 detailed data files”, U.S. Energy Information Administration, [On-line], Available: <https://www.eia.gov/electricity/data/eia861/>

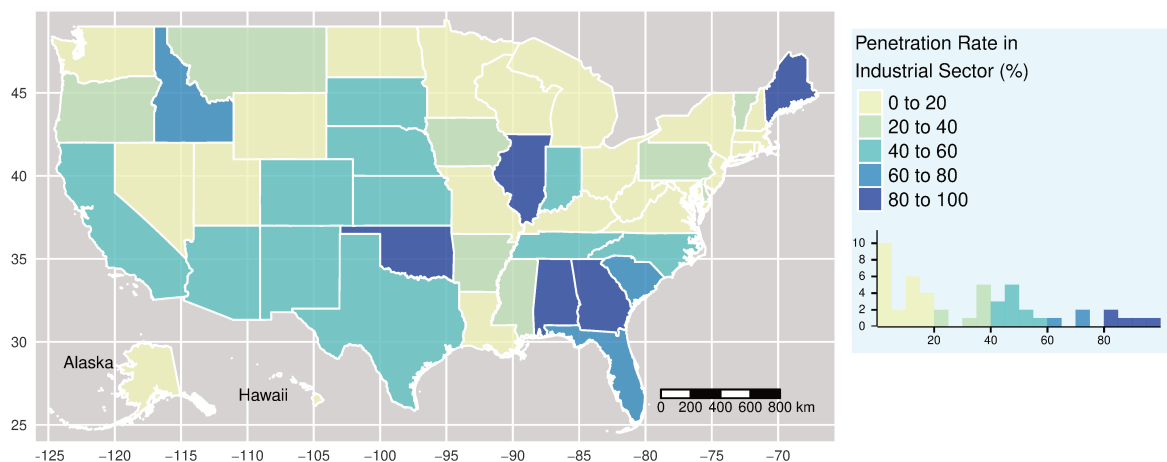


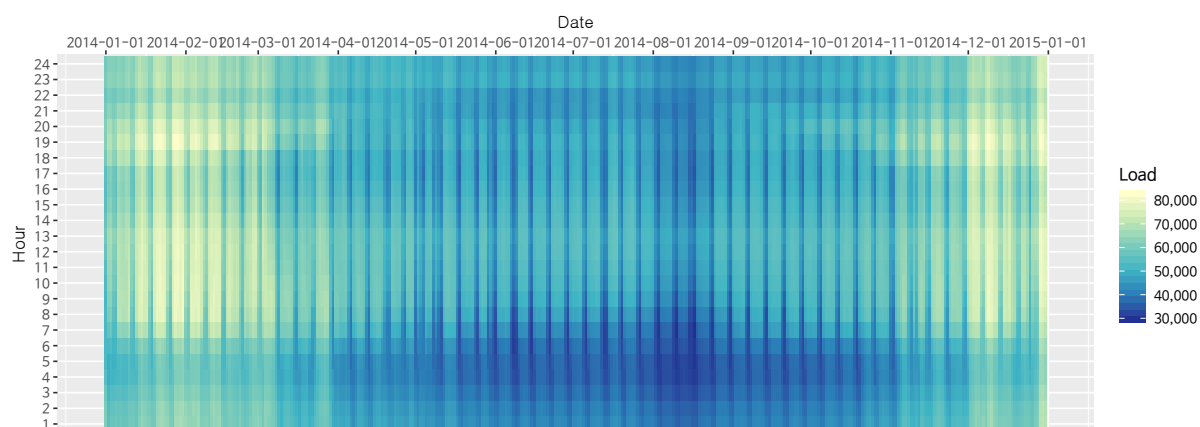
Figure A.4: Industrial Smart Meter Adoption Rates by State, 2016 in the U.S.

Source: *Annual Electric Power Industry Report*, by U.S. Energy Information Administration.; “Electric power sales, revenue, and energy efficiency Form EIA-861 detailed data files”, U.S. Energy Information Administration, [On-line], Available: <https://www.eia.gov/electricity/data/eia861/>

Table A.2: The Top 10 States in terms of the Number of Customers and AMI Penetration Rate in the Industrial Sector

Rank	State	No. of Customers	State	AMI Penetration Rate (%)
1	California	148,549	Oklahoma	96.0
2	Texas	105,552	Alabama	94.8
3	Nebraska	61,613	Illinois	88.9
4	Arkansas	36,428	Maine	82.7
5	Washington	29,012	Georgia	81.6
6	Idaho	27,847	Idaho	74.0
7	Oregon	24,628	Florida	72.4
8	Kansas	23,729	South Carolina	62.7
9	Pennsylvania	23,372	California	55.6
10	Georgia	21,774	Arizona	54.7

Source: *Annual Electric Power Industry Report*, by U.S. Energy Information Administration.; "Electric power sales, revenue, and energy efficiency Form EIA-861 detailed data files", U.S. Energy Information Administration, [On-line], Available: <https://www.eia.gov/electricity/data/eia861/>

**Figure A.5:** Heatmap of Loads, France in 2014 (MW)

Source: 'Data provided by ENTSO-E', ENTSO-E, "Consumption Data", [On-line], Available: <https://www.entsoe.eu/data/data-portal/consumption/Pages/default.aspx>

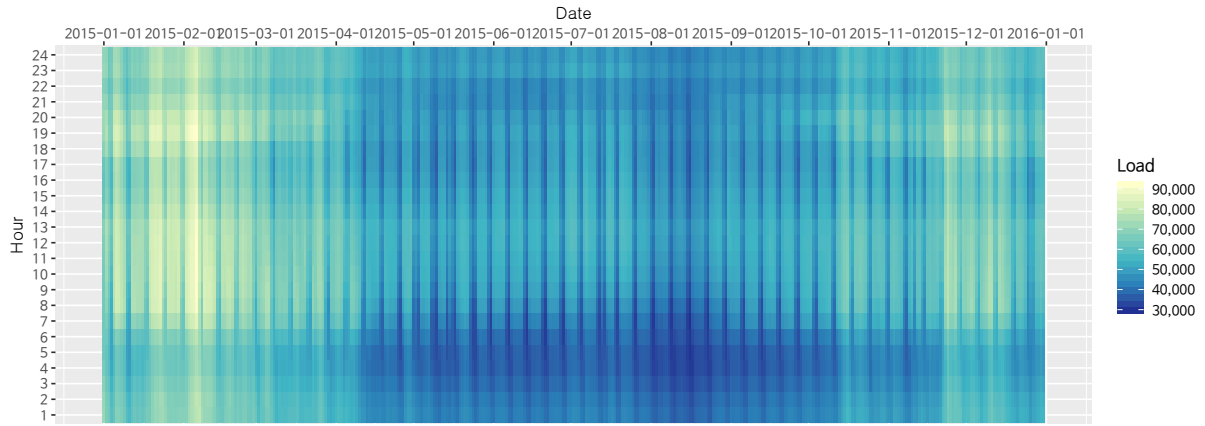


Figure A.6: Heatmap of Loads, France in 2015 (MW)

Source: 'Data provided by ENTSO-E', ENTSO-E, "Consumption Data", [On-line], Available: <https://www.entsoe.eu/data/data-portal/consumption/Pages/default.aspx>

Comparison to South Korea: Fig. A.20

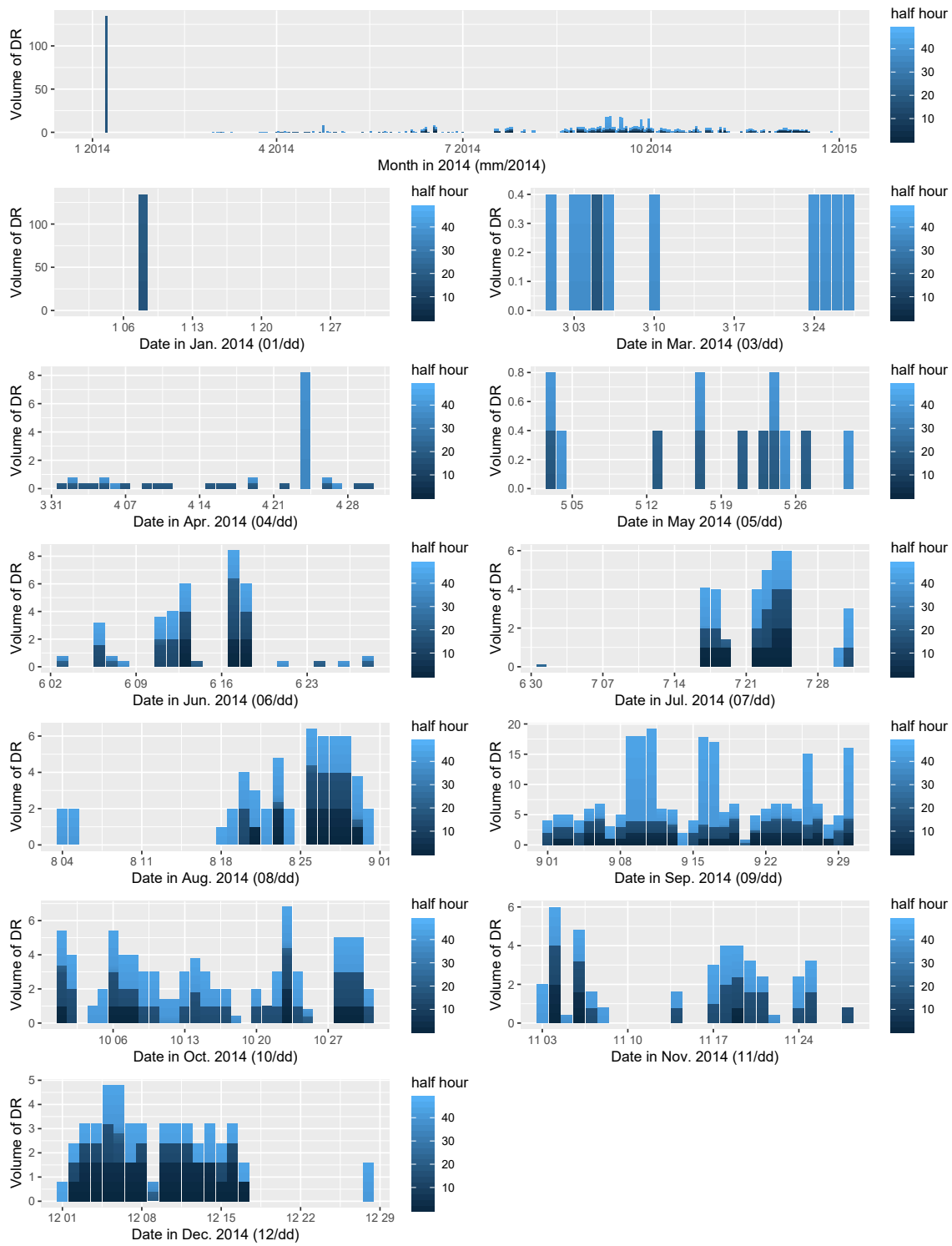


Figure A.7: The Volume of Demand Reduction of France in 2014 (Programmes d’Effacement Retenus agrégés, MW)

***half hour:** it means that the interval of the NEBEF is 30 minutes. For example, if the number of ‘half hour’ is 20, it means the volume between 09h30 and 10h00, and if it is 38, it means the volume between 18h30 and 19h00, etc.

Source: RTE’s PORTAIL CLIENTS, “Volumes d’Effacement NEBEF, tous Opérateurs d’Effacement confondus, agrégés à la maille France”, [On-line], Available: https://clients.rte-france.com/lang/fr/visiteurs/vie/nebef_effacements.jsp

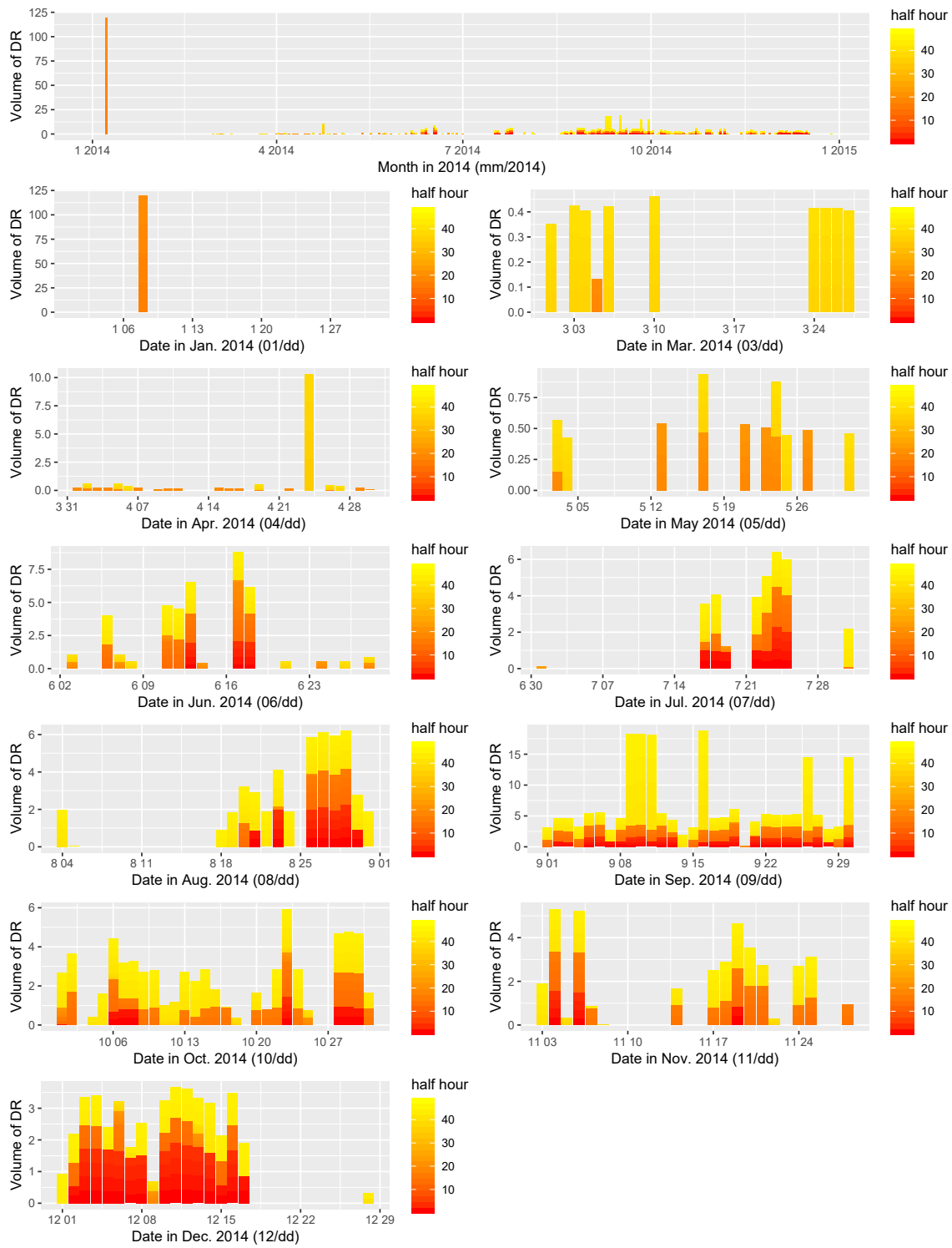


Figure A.8: The Volume of Demand Reduction of France in 2014 (Chroniques d’Effacement Réalisé agrégés, MW)

***halfhour:** it means that the interval of the NEBEF is 30 minutes. For example, if the number of ‘half hour’ is 20, it means the volume between 09h30 and 10h00, and if it is 38, it means the volume between 18h30 and 19h00, etc.

Source: RTE’s PORTAIL CLIENTS, “Volumes d’Effacement NEBEF, tous Opérateurs d’Effacement confondus, agrégés à la maille France”, [On-line], Available: https://clients.rte-france.com/lang/fr/visiteurs/vie/nebef_effacements.jsp

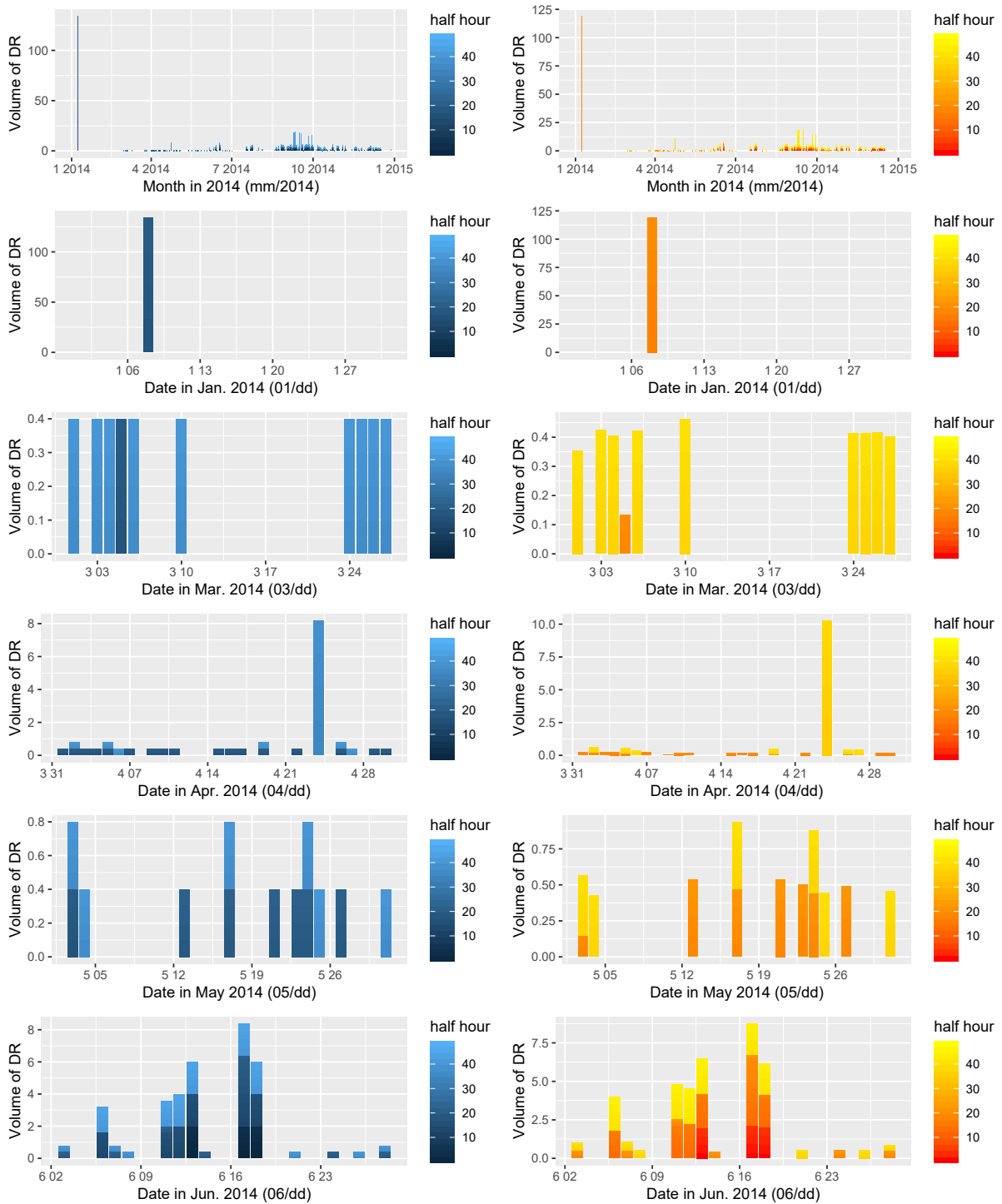


Figure A.9: For the Comparison between the two volumes of NEBEF (MW) in 2014

***half hour:** it means that the interval of the NEBEF is 30 minutes. For example, if the number of 'half hour' is 20, it means the volume between 09h30 and 10h00, and if it is 38, it means the volume between 18h30 and 19h00, etc.

Source: RTE's PORTAIL CLIENTS, "Volumes d'Effacement NEBEF, tous Opérateurs d'Effacement confondus, agrégés à la maille France", [On-line], Available: https://clients.rte-france.com/lang/fr/visiteurs/vie/nebef_effacements.jsp

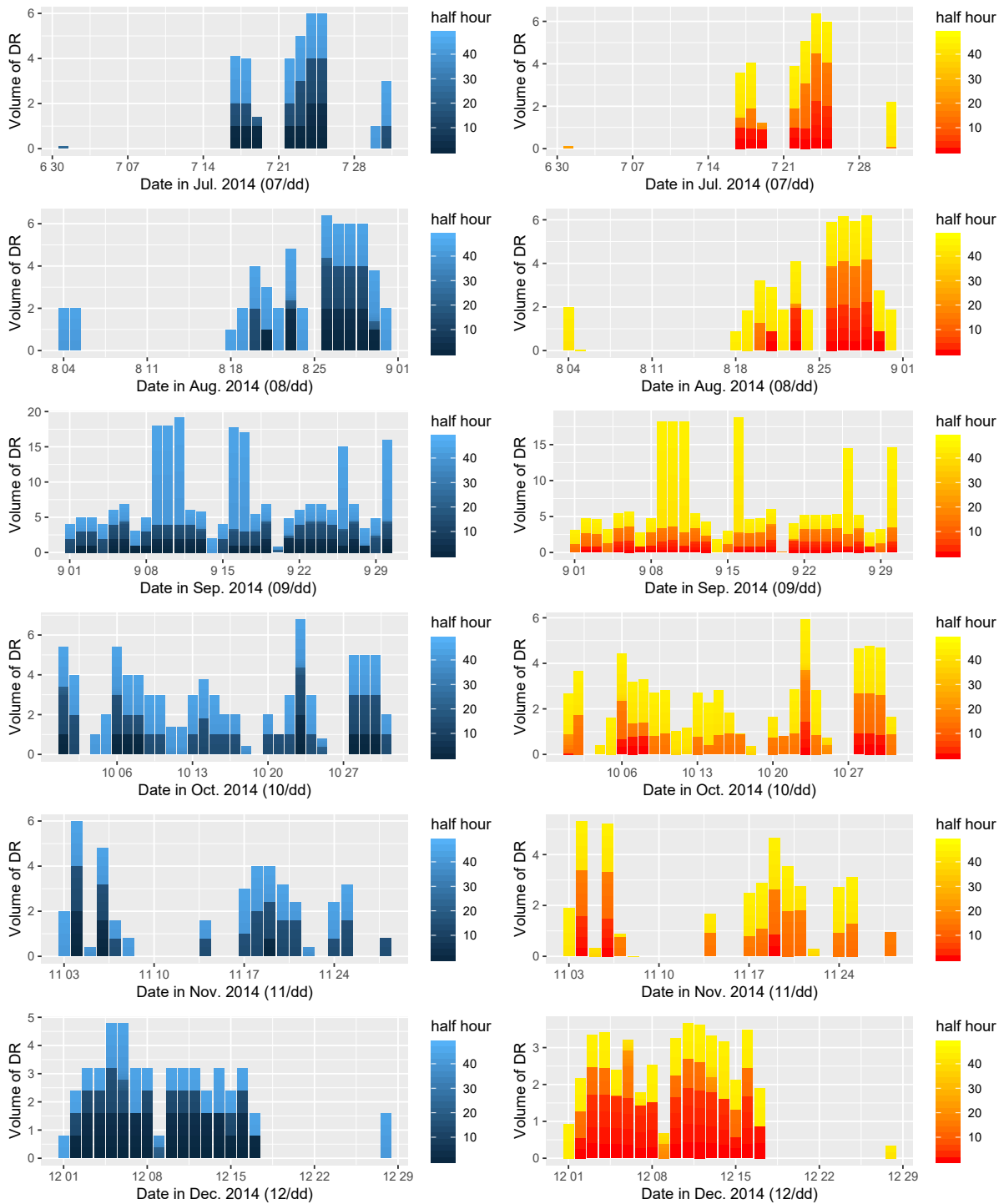


Figure A.10: For the Comparison between the two volumes of NEBEF (MW) in 2014 (Continued)

***half hour:** it means that the interval of the NEBEF is 30 minutes. For example, if the number of 'half hour' is 20, it means the volume between 09h30 and 10h00, and if it is 38, it means the volume between 18h30 and 19h00, etc.

Source: RTE's PORTAIL CLIENTS, "Volumes d'Effacement NEBEF, tous Opérateurs d'Effacement confondus, agrégés à la maille France", [On-line], Available: https://clients.rte-france.com/lang/fr/visiteurs/vie/nebef_effacements.jsp

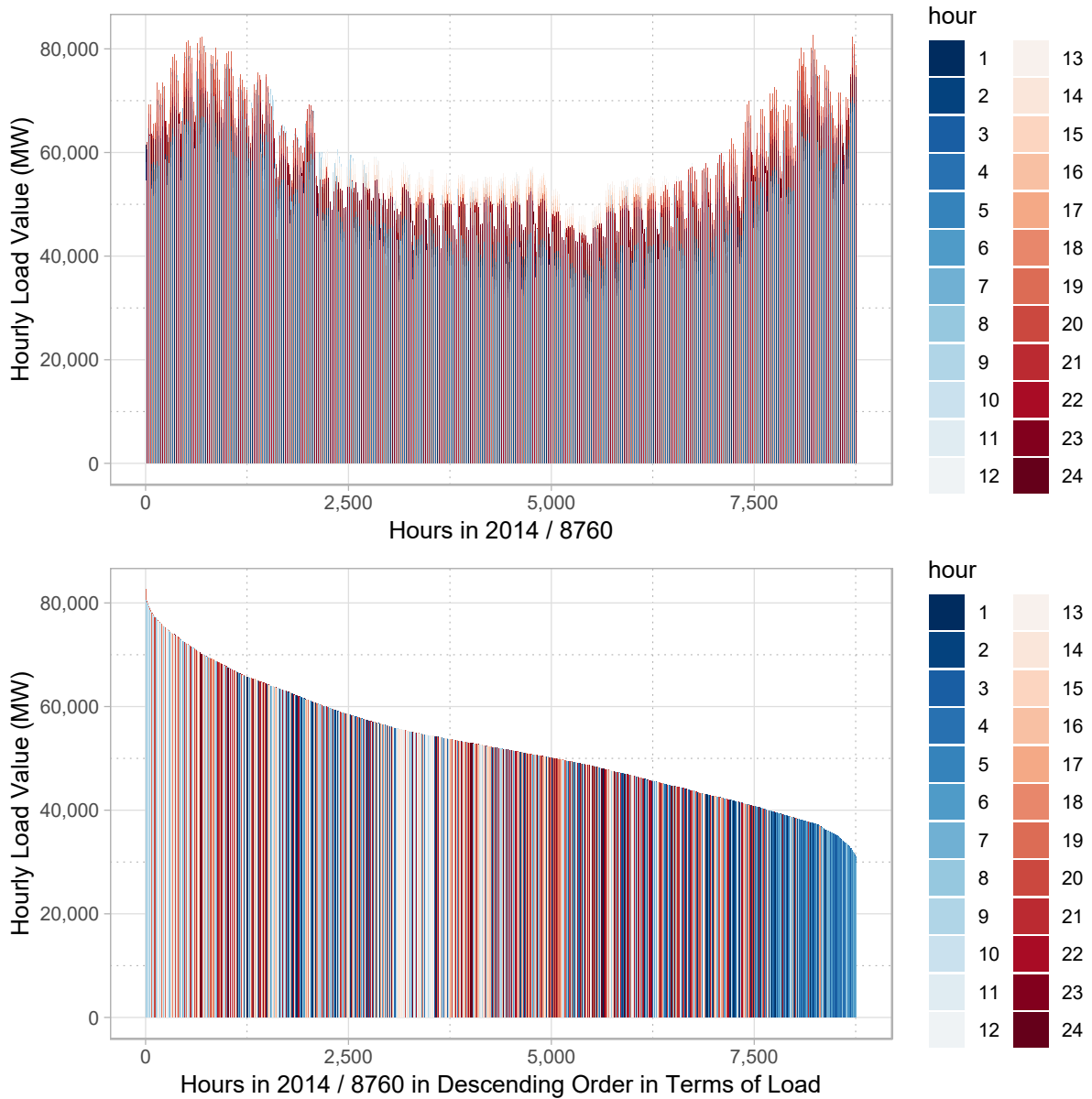


Figure A.11: Load Duration Curve of France in 2014 (MW)

Source: 'Data provided by ENTSO-E'. ENTSO-E, "Consumption Data", [On-line], Available: <https://www.entsoe.eu/data/data-portal/consumption/Pages/default.aspx>

..... Informations on Electricity Production & Consumption in 2014, France

Total Electricity Production in 2014: (Net) 540,600.00 GW.h.^[1], (Gross) 563,690 GW.h.^[2]

Total Electricity Consumption in 2014: 431,210 GW.h.^[3]

^[1] PRIS (IAEA), 2015, Country Statistics: France, [On-line], Available: <https://pris.iaea.org/PRIS/CountryStatistics/CountryDetails.aspx?current=FR>

^[2] IEA, 2017, *Electricity Information 2017*, p. III.197, Table 3a. Summary electricity production and consumption (TWh).

^[3] IEA, 2017, *Electricity Information 2017*, p. III.197, Table 3a. Summary electricity production and consumption (TWh).

Total Capacity in 2014: 128.94 GW.^[4]

Peak Load: 82,811 MW (date/time: 2014-12-09, 19:00).

Base Load: 29,697 MW.

Capacity Factor^[5]:

$$CF = \frac{\text{(Gross Production in a year (GWh))}}{\text{(Net Capacity (GW)} \times 365 \times 24)} = \frac{563,690 \text{ GWh}}{128.94 \times 365 \times 24 \text{ GWh}}$$

$$= 0.4990 \approx 49.9\%$$

Load Factor^[6]:

$$LF = \frac{\text{(Total Consumption in a year (GWh))}}{\text{(Peak Load (GW)} \times 365 \times 24)} = \frac{431,210 \text{ GWh}}{82.811 \times 365 \times 24 \text{ GWh}}$$

$$= 0.5944 \approx 59.4\%$$

Table A.3: Descriptive Statistics of Loads in 2014, 2015, 2016 (France)

	2014	2015	2016
Mean	52779.46	54006.72	54651.95
Std.Dev	10897.45	11642.45	11516.49
Min	29477.00	29590.00	30584.00
Q1	44397.50	45230.00	45992.50
Median	51827.50	52568.50	53351.00
Q3	60083.00	61809.00	63183.00
Max	82612.00	91934.00	88571.00
MAD	11533.89	12083.19	12602.84
IQR	15683.75	16577.50	17189.75
CV	0.21	0.22	0.21
Skewness	0.35	0.47	0.26
SE.Skewness	0.03	0.03	0.03
Kurtosis	-0.55	-0.34	-0.69
N.Valid	8760.00	8760.00	8784.00
Pct.Valid	100.00	100.00	100.00

^[4] [IEA, 2017, Electricity Information 2017](#), p. III.204, Table 7. Net maximum electricity generating capacity on 31 December (GW).

^[5] [Capacity facotr \(CF\)](#) is the capacity utilization rates. Different types of plants have different capacity factor ([Bhattacharyya, 2011](#), p. 230). It is defined as the annual gross electricity generation (in GWh) divided by the net capacity (in GW) times 365 (days/year) times 24 (hours/day). You can confirm the calculation of capacity factor for France: [IEA, 2017, Electricity Information 2017](#), p. III.205, Table 8. Capacity factors (%).

^[6] [The system load factor \(LF\)](#) is the ratio of area under the load-duration curve to the area of the rectangle formed by the peak load for entire duration of the year ([Bhattacharyya, 2011](#), p. 230).

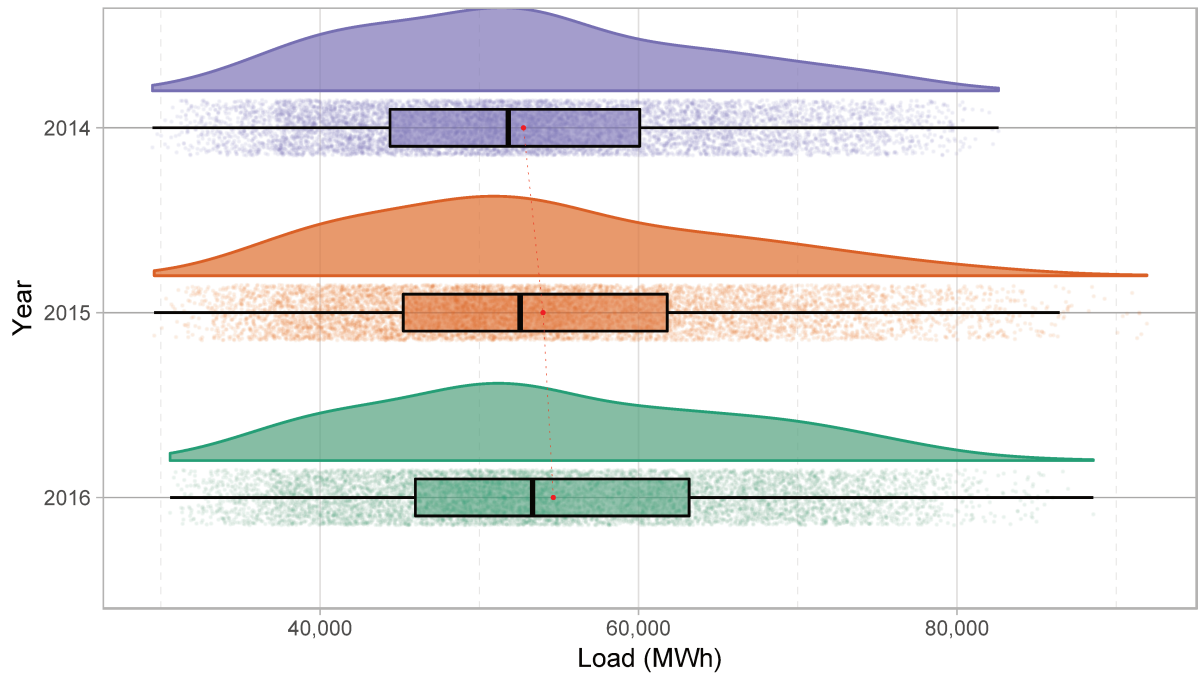


Figure A.12: Raincloud Plots of Loads in 2014, 2015, 2016 (France, MWh)

Credit for *Raincloud Plots*: [Allen et al. \(2018, 2019\)](#)

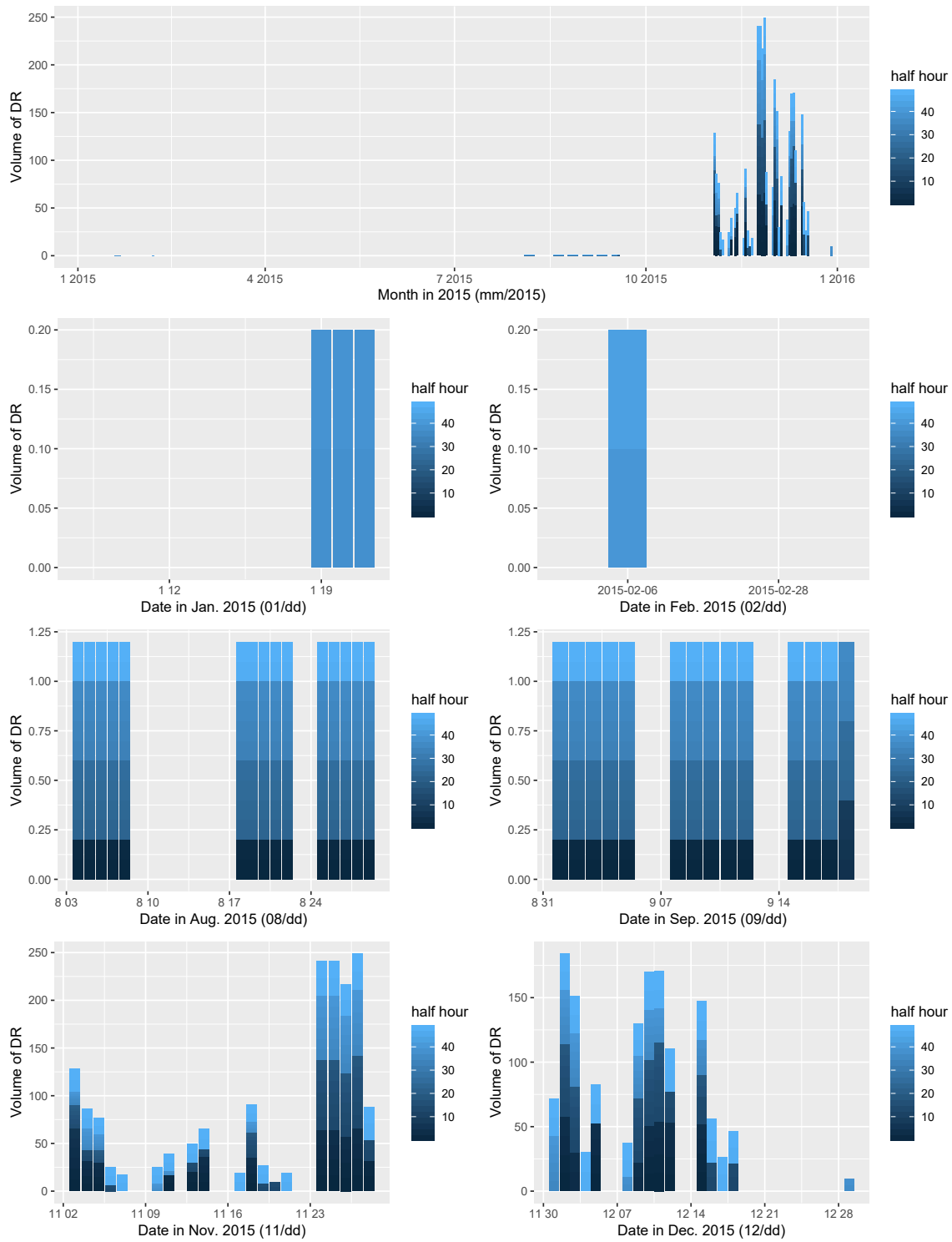


Figure A.13: The Volume of Demand Reduction of France in 2015 (Programmes d’Effacement Retenus agrégés, MW)

***half hour:** it means that the interval of the NEBEF is 30 minutes. For example, if the number of ‘half hour’ is 20, it means the volume between 09h30 and 10h00, and if it is 38, it means the volume between 18h30 and 19h00, etc.

Source: RTE’s PORTAIL CLIENTS, “Volumes d’Effacement NEBEF, tous Opérateurs d’Effacement confondus, agrégés à la maille France”, [On-line], Available: https://clients.rte-france.com/lang/fr/visiteurs/vie/nebef_effacements.jsp

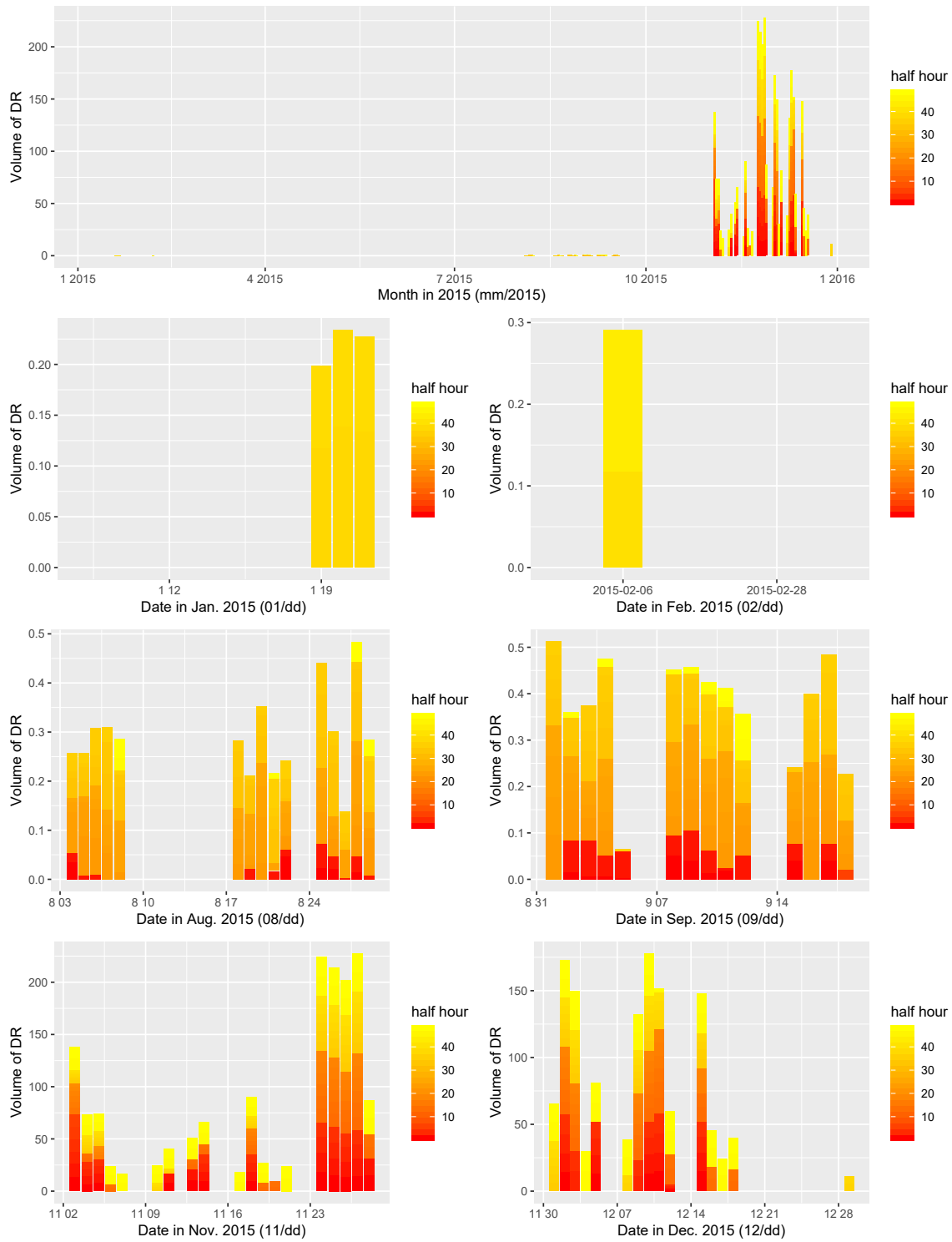


Figure A.14: The Volume of Demand Reduction of France in 2015 (Chroniques d’Effacement Réalisé agrégées, MW)

***halfhour**: it means that the interval of the NEBEF is 30 minutes. For example, if the number of ‘half hour’ is 20, it means the volume between 09h30 and 10h00, and if it is 38, it means the volume between 18h30 and 19h00, etc.

Source: RTE’s PORTAIL CLIENTS, “Volumes d’Effacement NEBEF, tous Opérateurs d’Effacement confondus, agrégés à la maille France”, [On-line], Available: https://clients.rte-france.com/lang/fr/visiteurs/vie/nebef_effacements.jsp

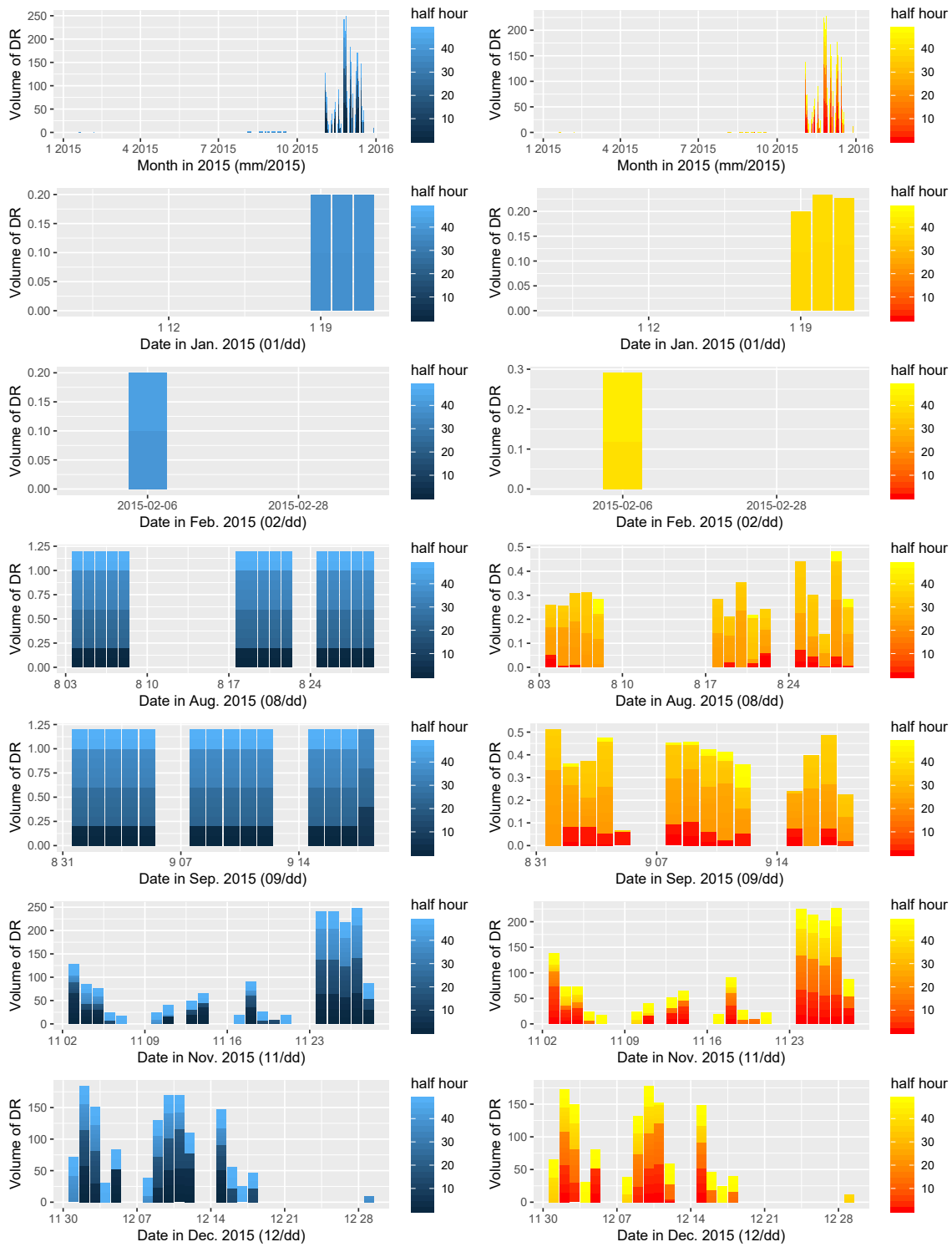


Figure A.15: For the Comparison between the two volumes of NEBEF (MW) in 2015

***half hour:** it means that the interval of the NEBEF is 30 minutes. For example, if the number of 'half hour' is 20, it means the volume between 09h30 and 10h00, and if it is 38, it means the volume between 18h30 and 19h00, etc.

Source: RTE's PORTAIL CLIENTS, "Volumes d'Effacement NEBEF, tous Opérateurs d'Effacement confondus, agrégés à la maille France", [On-line], Available: https://clients.rte-france.com/lang/fr/visiteurs/vie/nebef_effacements.jsp

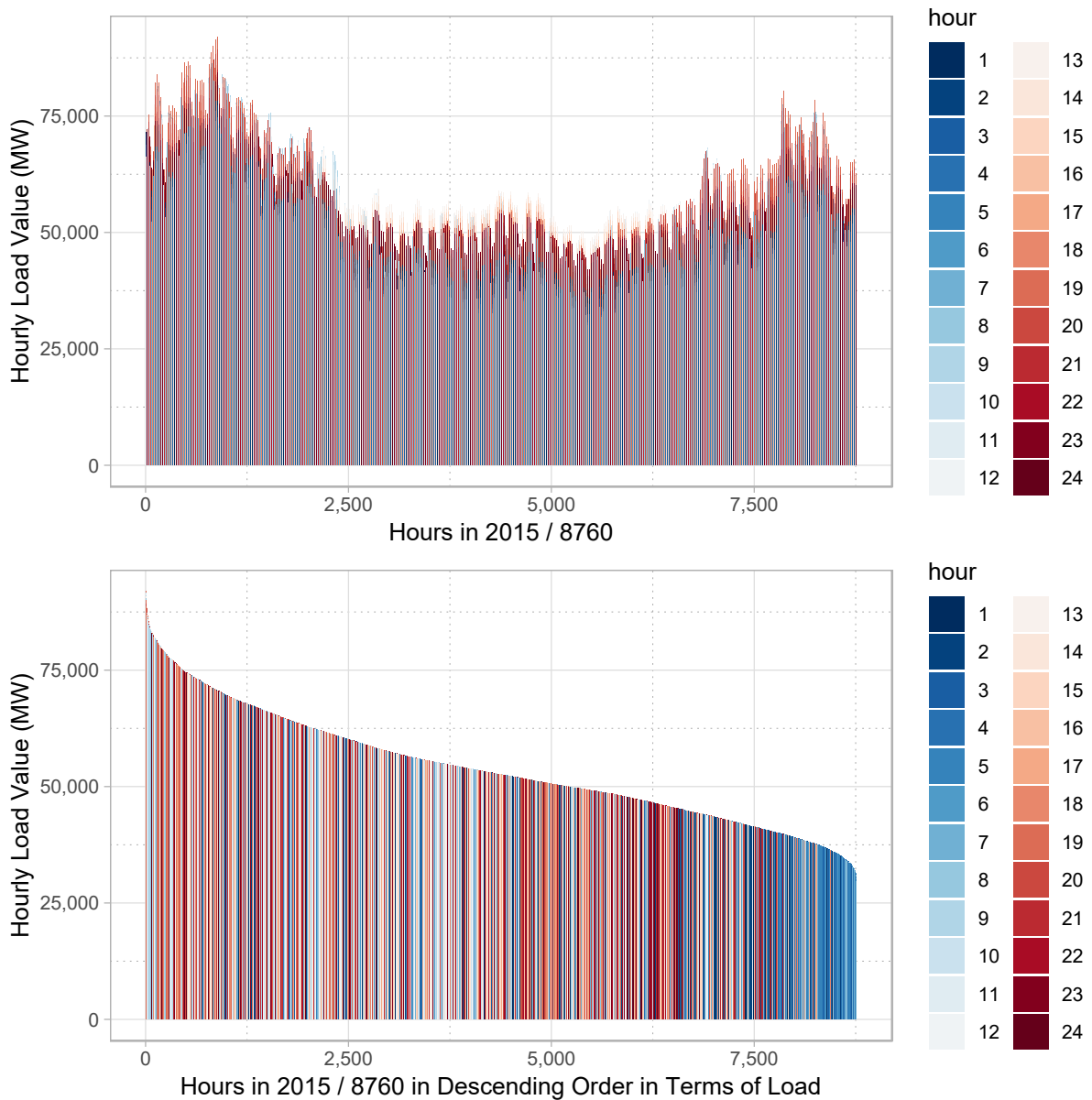


Figure A.16: Load Duration Curve of France in 2015 (MW)

Source: 'Data provided by ENTSO-E'. ENTSO-E, "Consumption Data", [On-line], Available: <https://www.entsoe.eu/data/data-portal/consumption/Pages/default.aspx>

Comparison to South Korea: Fig. A.22

..... Informations on Electricity Production & Consumption in 2015, France

Total Electricity Production in 2015: (Net) 546,800.00 GW.h.^[7], (Gross) 568,480 GW.h.^[8]

Total Electricity Consumption in 2015: 441,020 GW.h.^[9]

^[7] [PRIS \(IAEA\), 2016](https://pris.iaea.org/PRIS/CountryStatistics/CountryDetails.aspx?current=FR), Country Statistics: France, [On-line], Available: <https://pris.iaea.org/PRIS/CountryStatistics/CountryDetails.aspx?current=FR>

^[8] [IEA, 2017, Electricity Information 2017](#), p. III.197, Table 3a. Summary electricity production and consumption (TWh).

^[9] [IEA, 2017, Electricity Information 2017](#), p. III.197, Table 3a. Summary electricity production and consumption (TWh).

Total Capacity in 2015: 129.31 GW.^[10]

Peak Load: 91,611 MW (date/time: 2015-02-06, 19:00).

Base Load: 29,299 MW.

Capacity Factor:

$$CF = \frac{(\text{Gross Production in a year (GWh)})}{(\text{Net Capacity (GW)} \times 365 \times 24)} = \frac{568,480 \text{ GWh}}{129.31 \times 365 \times 24 \text{ GWh}}$$

$$= 0.5018 \approx 50.2\%$$

Load Factor:

$$LF = \frac{(\text{Total Consumption in a year (GWh)})}{(\text{Peak Load (GW)} \times 365 \times 24)} = \frac{441,020 \text{ GWh}}{91.611 \times 365 \times 24 \text{ GWh}}$$

$$= 0.5495 \approx 55.0\%$$

.....

^[10] [IEA, 2017](#), *Electricity Information 2017*, p. III.204, Table 7. Net maximum electricity generating capacity on 31 December (GW).

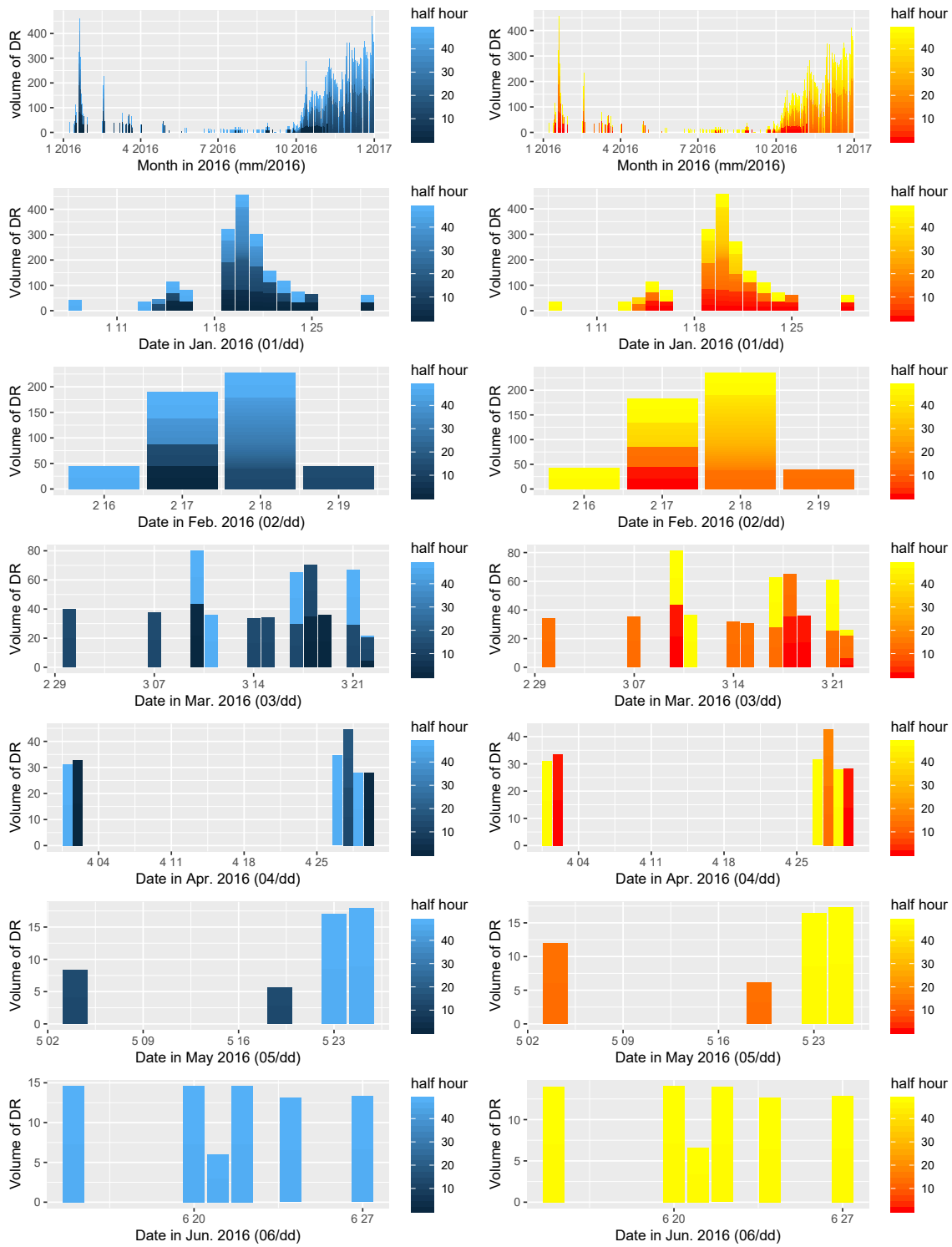


Figure A.17: For the Comparison between the two volumes of NEBEF (MW) in 2016

***half hour:** it means that the interval of the NEBEF is 30 minutes. For example, if the number of 'half hour' is 20, it means the volume between 09h30 and 10h00, and if it is 38, it means the volume between 18h30 and 19h00, etc.

Source: RTE's PORTAIL CLIENTS, "Volumes d'Effacement NEBEF, tous Opérateurs d'Effacement confondus, agrégés à la maille France", [On-line], Available: https://clients.rte-france.com/lang/fr/visiteurs/vie/nebef_effacements.jsp

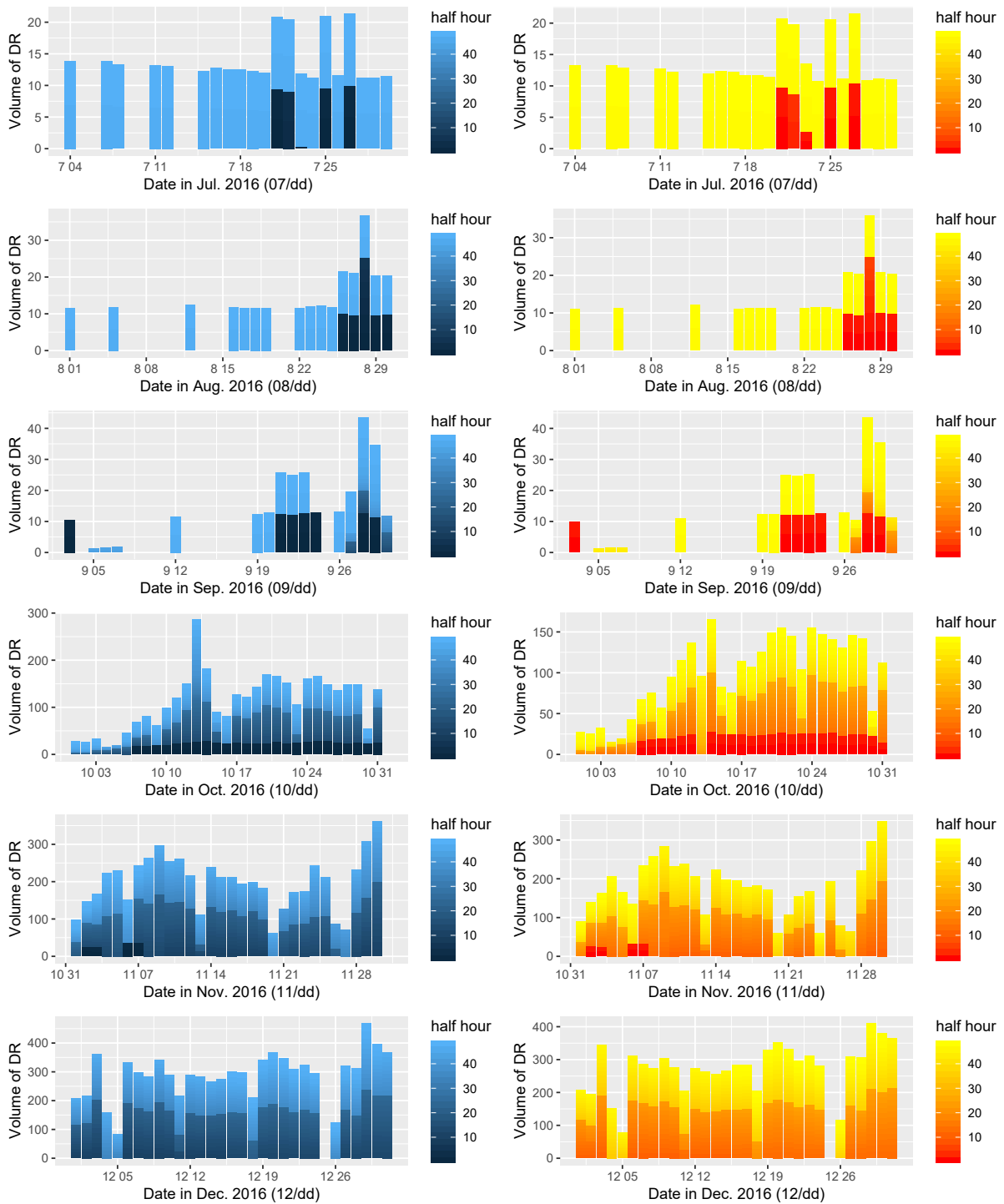


Figure A.18: For the Comparison between the two volumes of NEBEF (MW) in 2016 (Continued)

***half hour:** it means that the interval of the NEBEF is 30 minutes. For example, if the number of 'half hour' is 20, it means the volume between 09h30 and 10h00, and if it is 38, it means the volume between 18h30 and 19h00, etc.

Source: RTE's PORTAIL CLIENTS, "Volumes d'Effacement NEBEF, tous Opérateurs d'Effacement confondus, agrégés à la maille France", [On-line], Available: https://clients.rte-france.com/lang/fr/visiteurs/vie/nebef_effacements.jsp

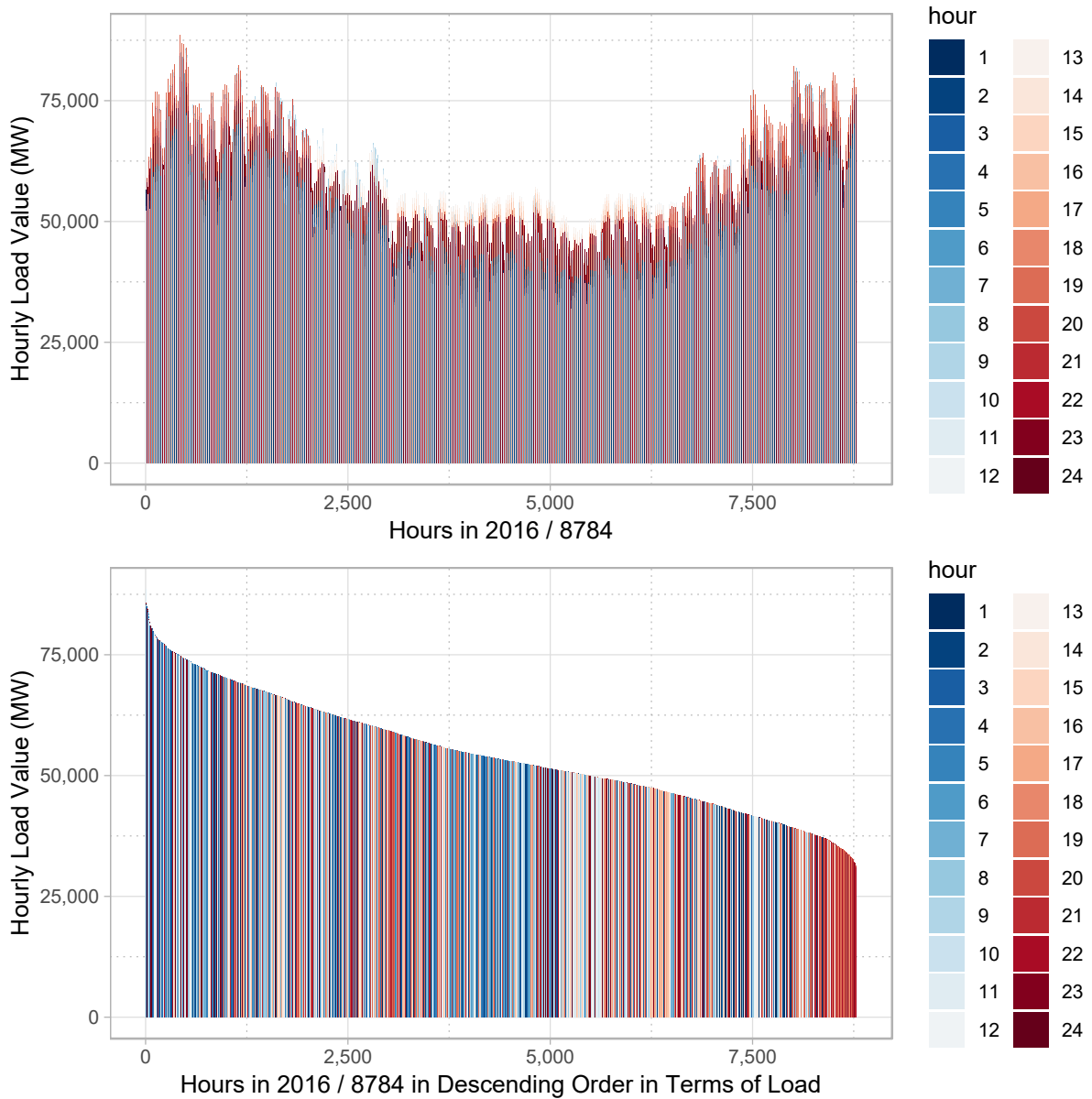


Figure A.19: Load Duration Curve of France in 2016 (MW)

Source: RTE's PORTAIL CLIENTS, "Historique des consommations journalières en puissance", [On-line], Available: https://clients.rte-france.com/lang/fr/clients_traders_fournisseurs/vie/vie_stats_conso_inst.jsp

Comparison to South Korea: Fig. 2.17

..... Informations on Electricity Production & Consumption in 2016, France

Total Electricity Production in 2016: (Net) 531,300.00 GW.h.^[11] (Gross) 556,180 GW.h.^[12]

^[11] PRIS (IAEA), 2017a, Country Statistics: France, [On-line], Available: <https://pris.iaea.org/PRIS/CountryStatistics/CountryDetails.aspx?current=FR>

^[12] IEA, 2018, *Electricity Information 2018*, p. III.199, Table 3a. Summary electricity production and consumption (TWh).

Total Electricity Consumption in 2016: 449,200 GW.h. ^[13]

Total Capacity in 2016: 130.79 GW. ^[14]

Peak Load: 88,571 MW (date/time: 2016-01-18, 19:00).

Base Load: 30,584 MW (date/time: 2016-08-07, 07:00).

Capacity Factor:

$$CF = \frac{\text{Gross Production in a year (GWh)}}{\text{Net Capacity (GW)} \times 366 \times 24} = \frac{556,180 \text{ GWh}}{130.79 \times 366 \times 24 \text{ GWh}}$$

$$= 0.4841 \approx 48.4\%$$

Load Factor:

$$LF = \frac{\text{Total Consumption in a year (GWh)}}{\text{Peak Load (GW)} \times 366 \times 24} = \frac{449,200 \text{ GWh}}{88.571 \times 366 \times 24 \text{ GWh}}$$

$$= 0.5773 \approx 57.7\%$$

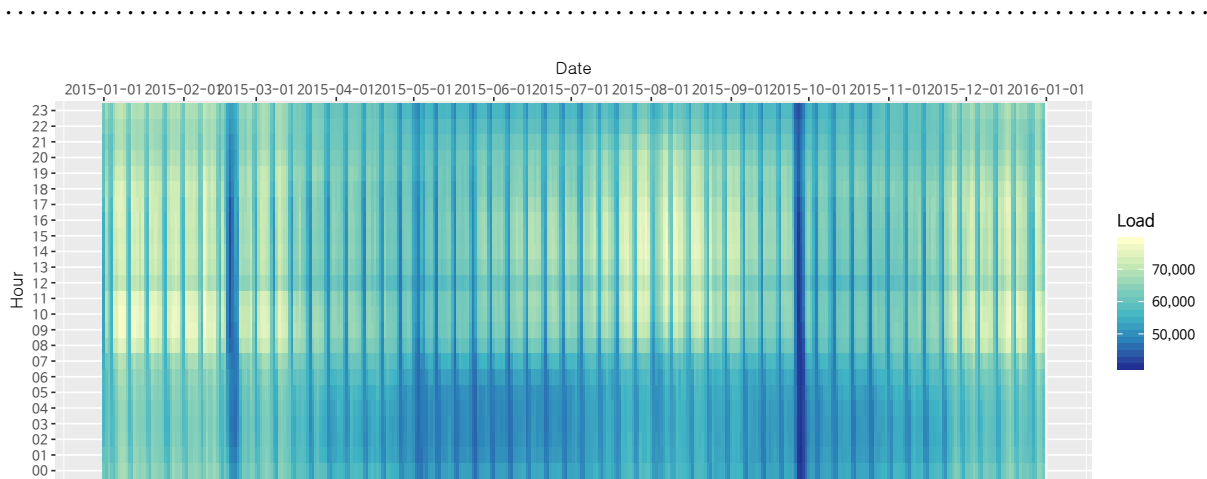


Figure A.20: Heatmap of Loads, South Korea in 2015 (MW)

Source: “대국민 전력수급현황 공유 시스템” (Public Information Sharing System on Electricity Demand and Supply), KPX, [On-line], Available: <https://openapi.kpx.or.kr/sukub.do#>

Comparison to France: Fig. A.6

..... Informations on Electricity Production & Consumption in 2016, South Korea.....

Total Electricity Production in 2016: (Net) 509,016.00 GW.h. (PRIS (IAEA), 2017b), (Gross) 562,600 GW.h. ^[15]

Total Electricity Consumption in 2016: 530,140 GW.h. ^[16]

Total Capacity in 2016: 111.20 GW. ^[17]

^[13] IEA, 2018, *Electricity Information 2018*, p. III.199, Table 3a. Summary electricity production and consumption (TWh).

^[14] IEA, 2018, *Electricity Information 2018*, p. III.206, Table 7. Net maximum electricity generating capacity on 31 December (GW).

^[15] IEA, 2018, *Electricity Information 2018*, p. III.315, Table 3a. Summary electricity production and consumption (TWh).

^[16] IEA, 2018, *Electricity Information 2018*, p. III.315, Table 3a. Summary electricity production and consumption (TWh).

^[17] IEA, 2018, *Electricity Information 2018*, p. III.322, Table 7. Net maximum electricity generating capacity on 31 December (GW).

Peak Load (Max.): 85,183 MW (date/time: 2016-08-12, 17:00).

Base Load (Min.): 42,121 MW.

Capacity Factor:

$$CF = \frac{(\text{Gross Production in a year (GWh)})}{(\text{Net Capacity (GW)} \times 366 \times 24)} = \frac{562,600 \text{ GWh}}{111.20 \times 366 \times 24 \text{ GWh}}$$

$$= 0.5759 \approx 57.6\%$$

Load Factor:

$$LF = \frac{(\text{Total Consumption in a year (GWh)})}{(\text{Peak Load (GW)} \times 366 \times 24)} = \frac{530,140 \text{ GWh}}{85.183 \times 366 \times 24 \text{ GWh}}$$

$$= 0.7085 \approx 70.9\%$$

Table A.4: Descriptive Statistics of Loads in 2015, 2016 (South Korea)

	2015	2016
Mean	59983.47	61597.32
Std.Dev	7198.54	7887.37
Min	40009.50	42373.73
Q1	54220.77	55215.65
Median	60292.17	61421.18
Q3	65049.00	66810.91
Max	78806.07	85184.64
MAD	8007.68	8605.82
IQR	10826.54	11593.94
CV	0.12	0.13
Skewness	0.06	0.32
SE.Skewness	0.03	0.03
Kurtosis	-0.66	-0.44
N.Valid	8760.00	8784.00
Pct.Valid	100.00	100.00

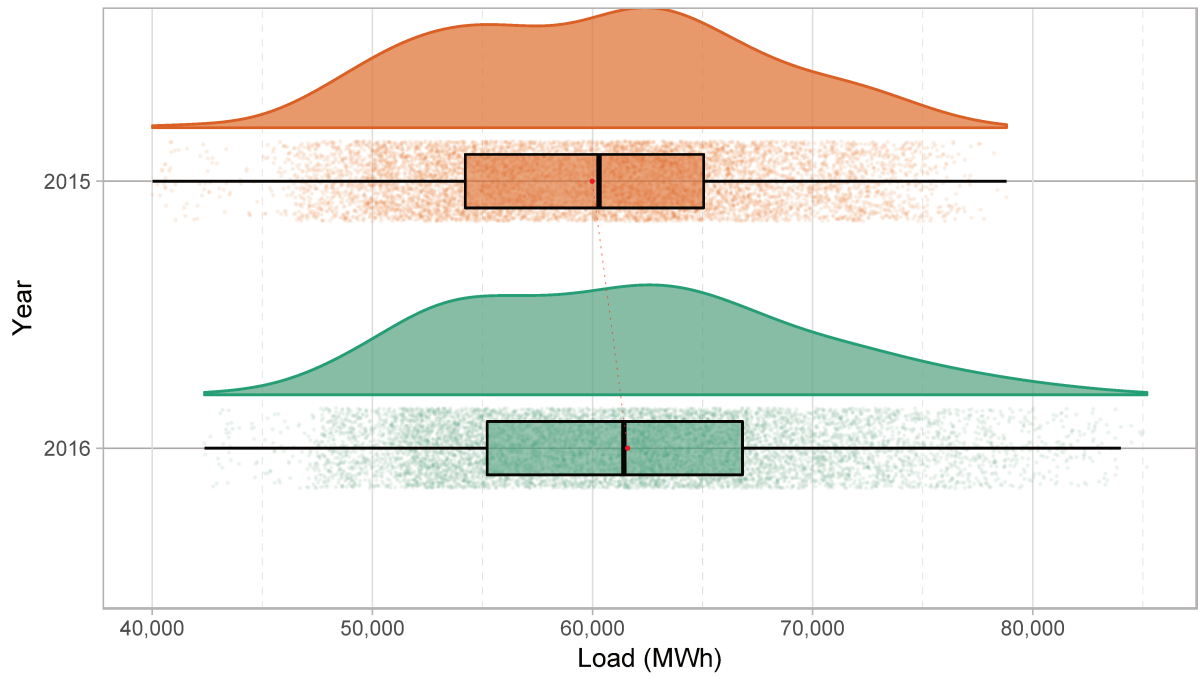


Figure A.21: Raincloud Plots of Loads in 2015, 2016 (South Korea, MWh)

Credit for *Raincloud Plots*: [Allen et al. \(2018, 2019\)](#)

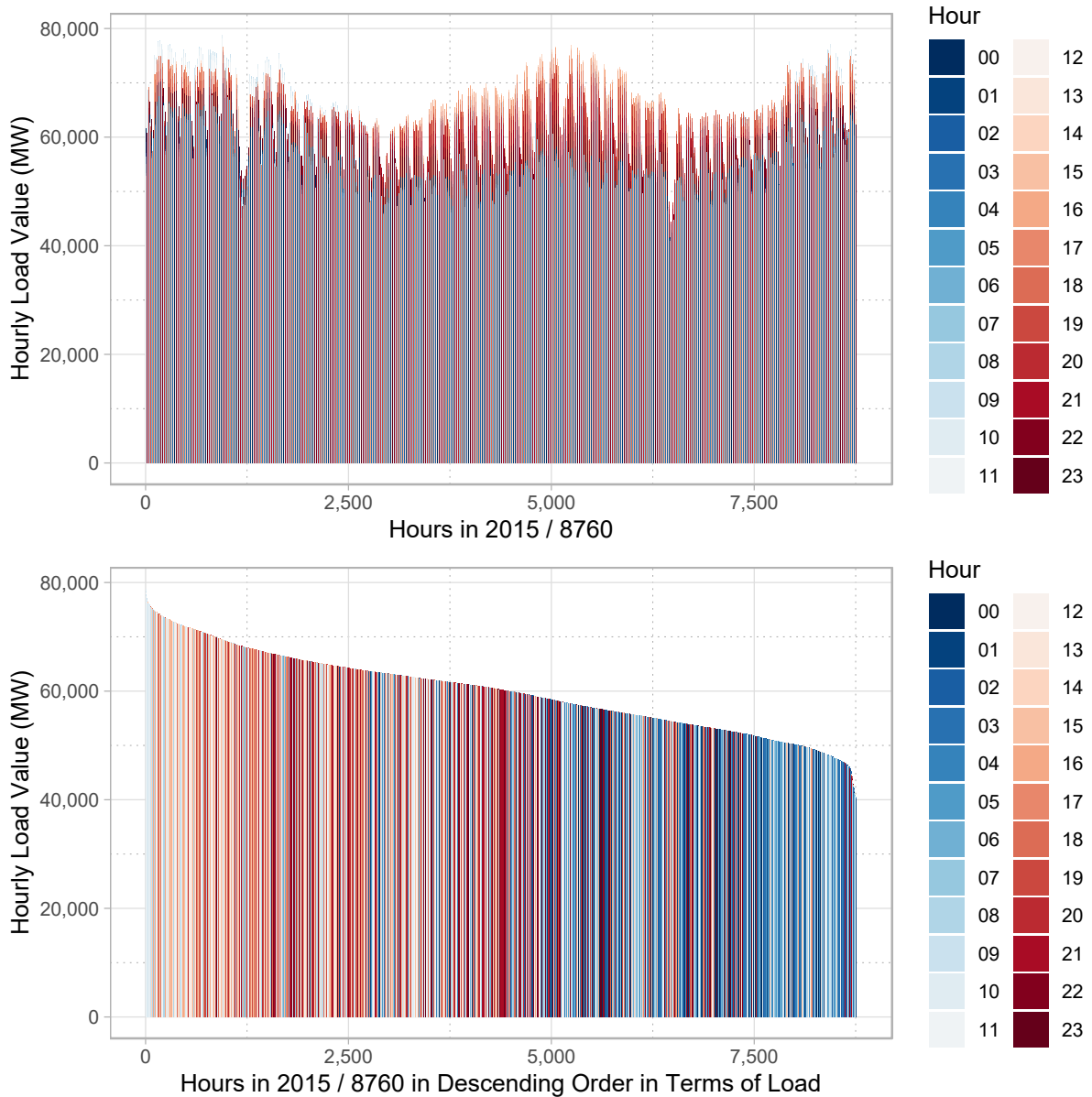


Figure A.22: Load Duration Curve of South Korea in 2015 (MW)

Source: “대국민 전력수급현황 공유 시스템” (Public Information Sharing System on Electricity Demand and Supply), KPX, [On-line], Available: <https://openapi.kpx.or.kr/sukub.do#>

Comparison to France: Fig. A.16

..... Informations on Electricity Production & Consumption in 2015, South Korea.....

Total Electricity Production in 2015: (Gross) 552,880 GW.h.^[18]

Total Electricity Consumption in 2015: 506,650 GW.h.^[19]

Total Capacity in 2015: 103.02 GW.^[20]

^[18] IAEA, 2017, *Electricity Information 2017*, p. III.313, Table 3a. Summary electricity production and consumption (TWh).

^[19] IAEA, 2017, *Electricity Information 2017*, p. III.313, Table 3a. Summary electricity production and consumption (TWh).

^[20] IAEA, 2017, *Electricity Information 2017*, p. III.320, Table 7. Net maximum electricity generating capacity on 31 December (GW).

Peak Load (Max.): 78,790 MW (date/time: 2015-02-09, 11:00).

Base Load (Min.): 39,592 MW.

Capacity Factor:

$$CF = \frac{(\text{Gross Production in a year (GWh)})}{(\text{Net Capacity (GW)} \times 365 \times 24)} = \frac{552,880 \text{ GWh}}{103.02 \times 365 \times 24 \text{ GWh}}$$

$$= 0.6126 \approx 61.3\%$$

Load Factor:

$$LF = \frac{(\text{Total Consumption in a year (GWh)})}{(\text{Peak Load (GW)} \times 365 \times 24)} = \frac{506,650 \text{ GWh}}{78.79 \times 365 \times 24 \text{ GWh}}$$

$$= 0.7340 \approx 73.4\%$$

Table A.5: The Performance on the Reductions of Electricity Demand (MWh)

Year	Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.	Total
2014	-	-	-	-	-	-	-	-	-	-	-	4,750	4,750
2015	551	4,964	6,478	52,102	47,845	26,971	21,439	19,846	6,095	13,280	3,469	1,812	204,852
2016	28,069	32,090	13,996	11,609	11,257	35,796	60,468	87,714	31,977	21,828	72,423	15,400	422,627

Source: "Electric Power Market Statistics in 2016". KPX, 2017, [On-line], Available: <http://epsis.kpx.or.kr/epsisnew/selectEkifBoardList.do?menuId=090141&boardId=003141>

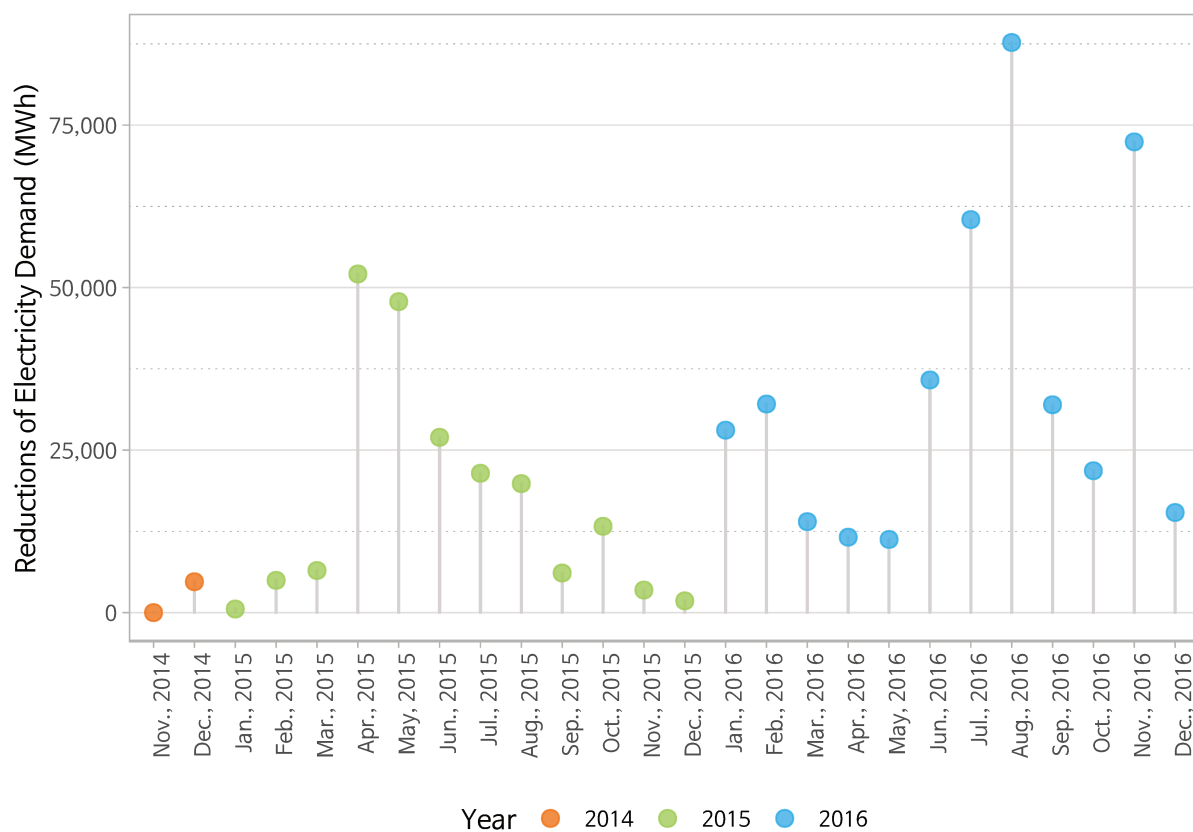


Figure A.23: The Reductions of the Electricity Demand at the South Korean DRTM in 2014, 2015, and 2016

Source: "Electric Power Market Statistics in 2016", KPX, 2017, [On-line], Available: <http://epsis.kpx.or.kr/epsisnew/selectEkifBoardList.do?menuId=090141&boardId=003141>

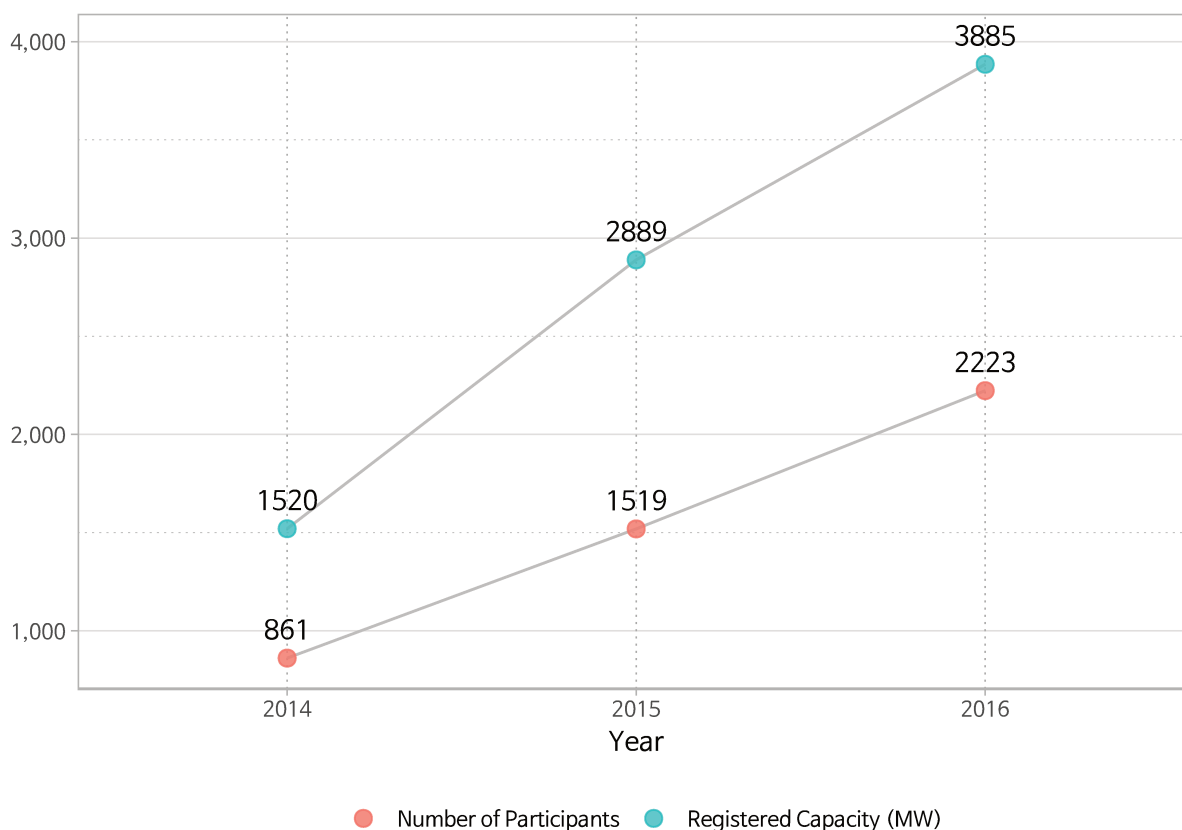


Figure A.24: The Registered Capacity and the Number of Participants of the South Korean DRTM in 2014, 2015, and 2016

Source: “Electric Power Market Statistics in 2016”, KPX, 2017, [On-line], Available: <http://epsis.kpx.or.kr/epsisnew/selectEkifBoardList.do?menuId=090141&boardId=003141>

Table A.6: The Composition of Participants by Industry

Year	Manufacturing	Commercial	Service	Agricultural	Total
2014	250 (29.0%)	370 (43.0%)	129 (15.0%)	112 (13.0%)	861
2015	739 (48.7%)	457 (30.1%)	279 (18.3%)	44 (2.9%)	1,519
2016	1,307 (58.8%)	386 (17.4%)	482 (21.6%)	48 (2.2%)	2,223

Source: “Electric Power Market Statistics in 2016”, KPX, 2017, [On-line], Available: <http://epsis.kpx.or.kr/epsisnew/selectEkifBoardList.do?menuId=090141&boardId=003141>

Table A.7: The Payments for the Capacity and Reductions of Electricity Demand (Korean million Won, ₩1,000,000)

Year	Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.	Total
2014	-	-	-	-	-	-	-	-	-	-	537	3,618	4,155
2015	7,054	6,224	7,072	5,072	3,840	11,664	14,168	11,637	9,144	5,118	9,767	14,022	104,782
2016	14,379	12,544	13,169	4,577	3,723	15,400	19,241	20,351	13,170	6,949	19,228	22,780	165,511

Source: “Electric Power Market Statistics in 2016”, KPX, 2017, [On-line], Available: <http://epsis.kpx.or.kr/epsisnew/selectEkifBoardList.do?menuId=090141&boardId=003141>

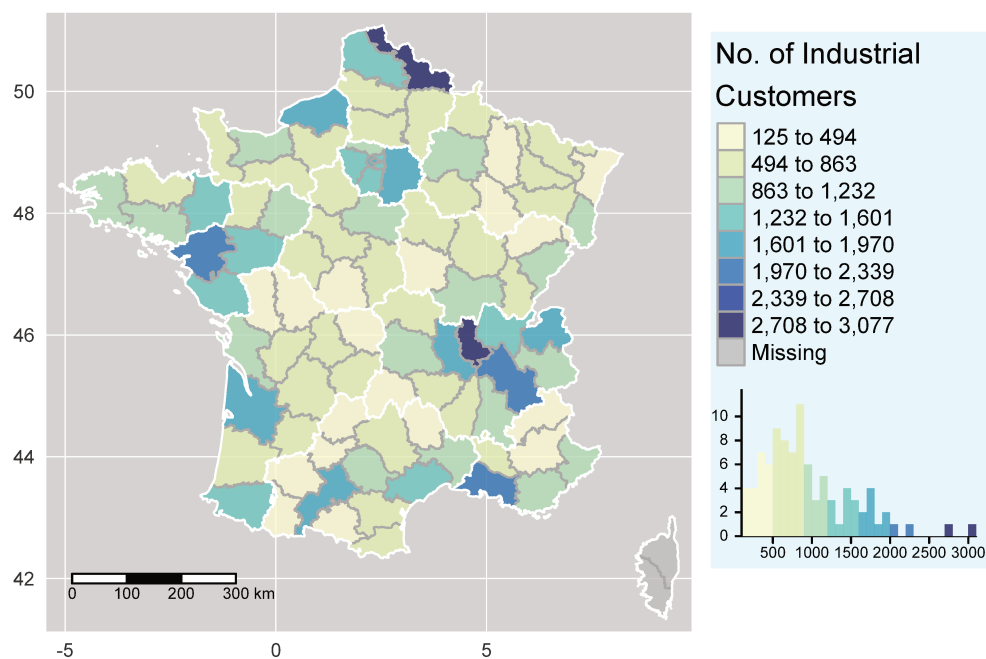


Figure A.25: The Number of Industrial Customers by Département, 2016 in France

Source: “Consommation électrique annuelle à la maille département”, 2018, by Enedis, [On-line], Available: <https://goo.gl/kqVMi2>

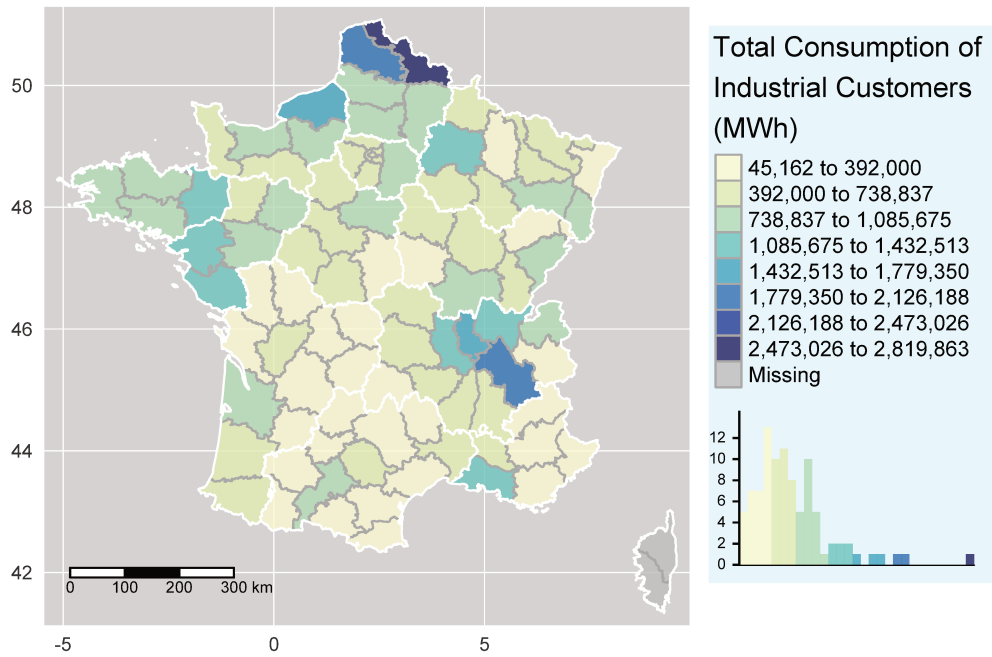


Figure A.26: The Total Consumption of Industrial Customers by Département, 2016 in France (MWh)

Source: “Consommation électrique annuelle à la maille département”, 2018, by Enedis, [Online], Available: <https://goo.gl/kqVMi2>

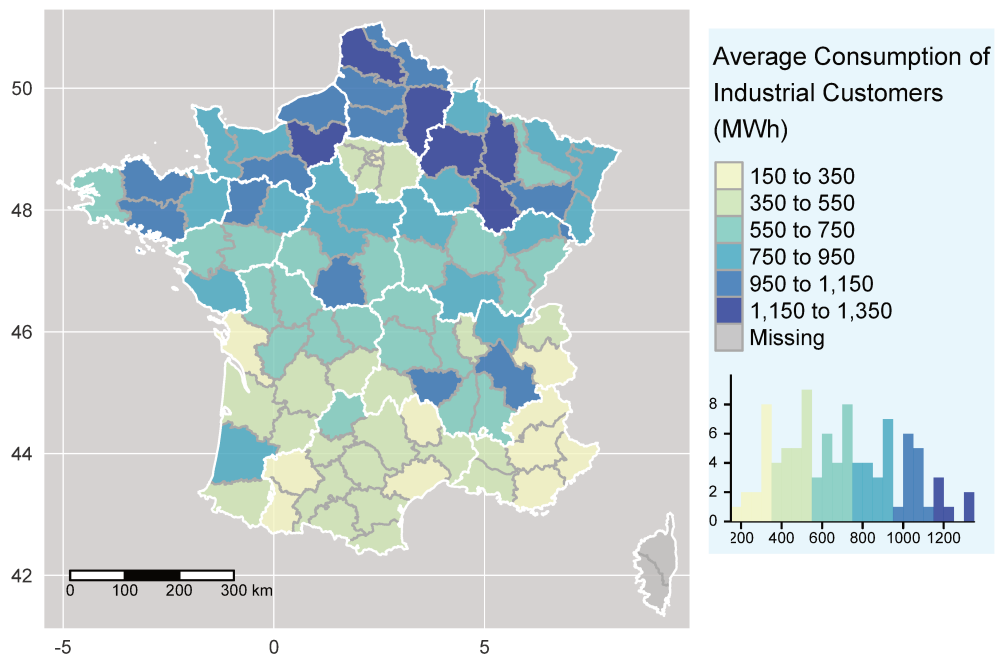


Figure A.27: The Average Consumption of Industrial Customers by Département, 2016 in France (MWh)

Source: “Consommation électrique annuelle à la maille département”, 2018, by Enedis, [Online], Available: <https://goo.gl/kqVMi2>

Table A.8: The Top 10 Département in terms of Number, Total Consumption, and Average Consumption in Industrial Sector

Rank	Dépt.	No. Sites	Dépt.	Total Conso. (MWh)	Dépt.	Avg. Conso. (MWh)
1	Rhone	3,077	Nord	2,819,863	Haute-Marne	1,349.214
2	Nord	2,796	Iserre	2,050,999	Pas-de-Calais	1,308.478
3	Bouches-du-Rhone	2,211	Pas-de-Calais	1,977,110	Meuse	1,225.497
4	Iserre	2,033	Seine-Maritime	1,732,074	Aisne	1,171.156
5	Loire-Atlantique	1,997	Rhone	1,622,787	Marne	1,165.554
6	Gironde	1,948	Ille-et-Vilaine	1,418,817	Eure	1,161.112
7	Seine-et-Marne	1,854	Loire-Atlantique	1,399,995	Vosges	1,103.791
8	Haute-Savoie	1,792	Marne	1,352,043	Somme	1,096.089
9	Haute-Garonne	1,780	Loire	1,249,746	Mayenne	1,085.703
10	Paris	1,766	Ain	1,224,672	Indre	1,063.306

Source: "Consommation électrique annuelle à la maille département", 2018, by Enedis, [On-line], Available: <https://goo.gl/kqVMi2>

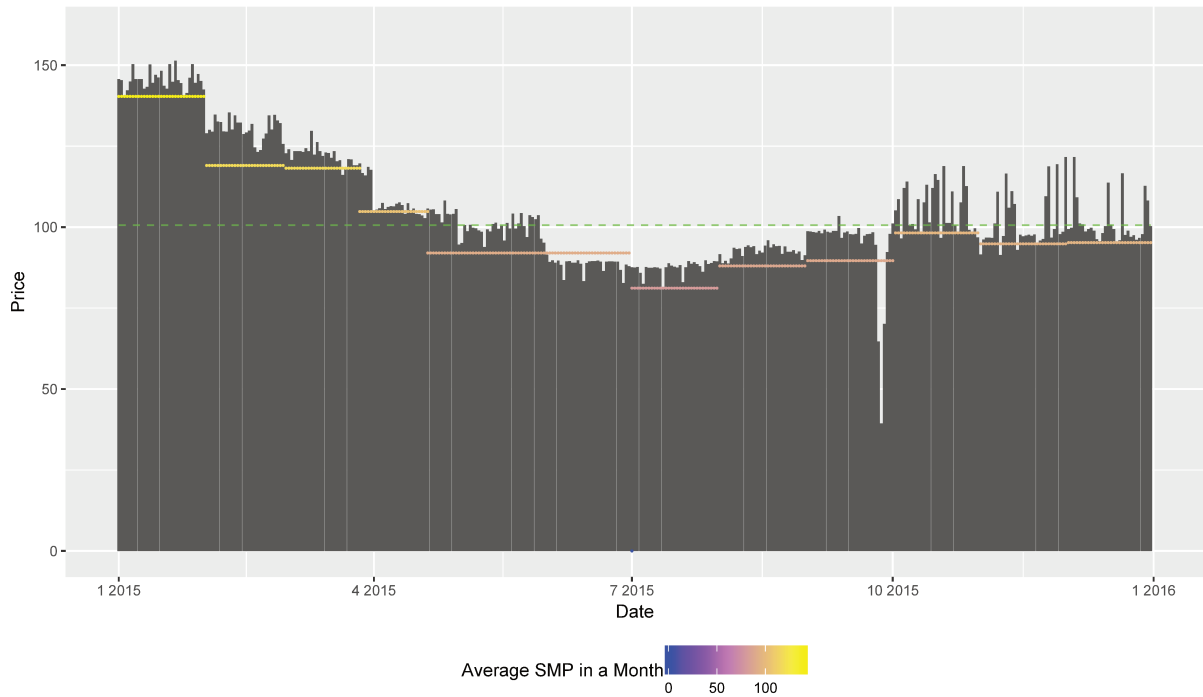


Figure A.28: SMP, South Korea in 2015 (Korean Won (₩)/kWh)

Source: “SMP”. KPX, [On-line], Available: <http://www.kpx.or.kr/www/contents.do?key=225>

Comparison to France: Fig. A.30

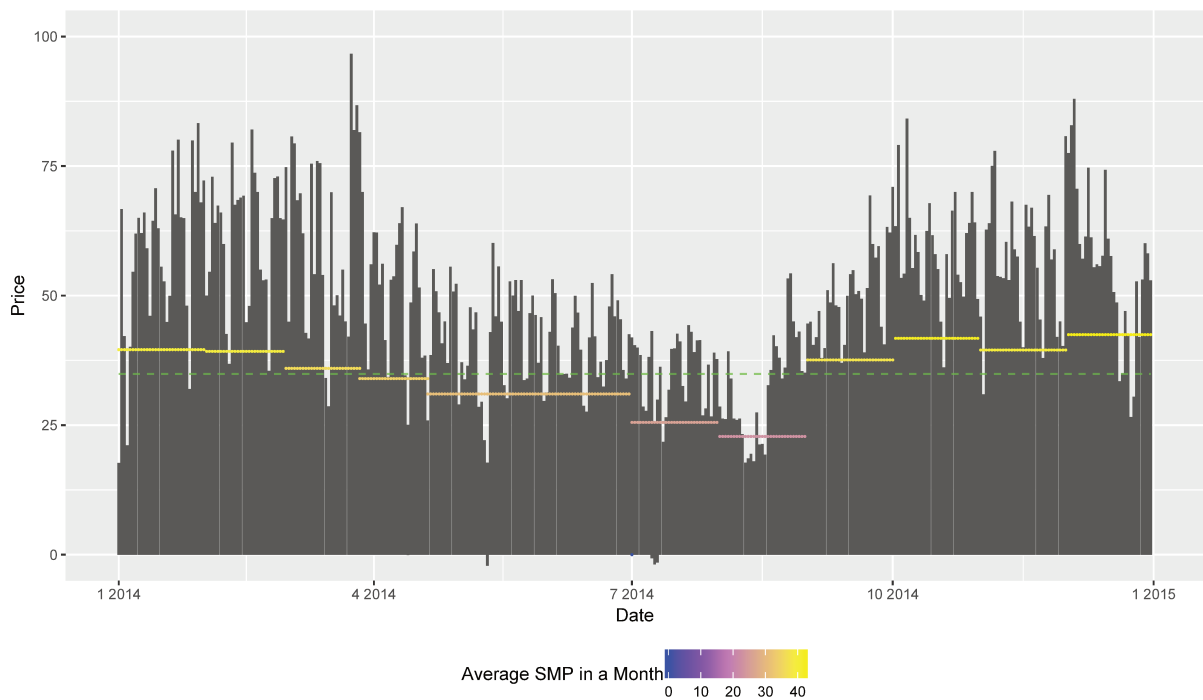


Figure A.29: SMP, France in 2014 (EUR(€)/MWh)

Source: “Prices - EPEX Spot Market Auction - France”, EPEX, [On-line], Available: http://www.epexspot.com/fr/donnees_de_marche

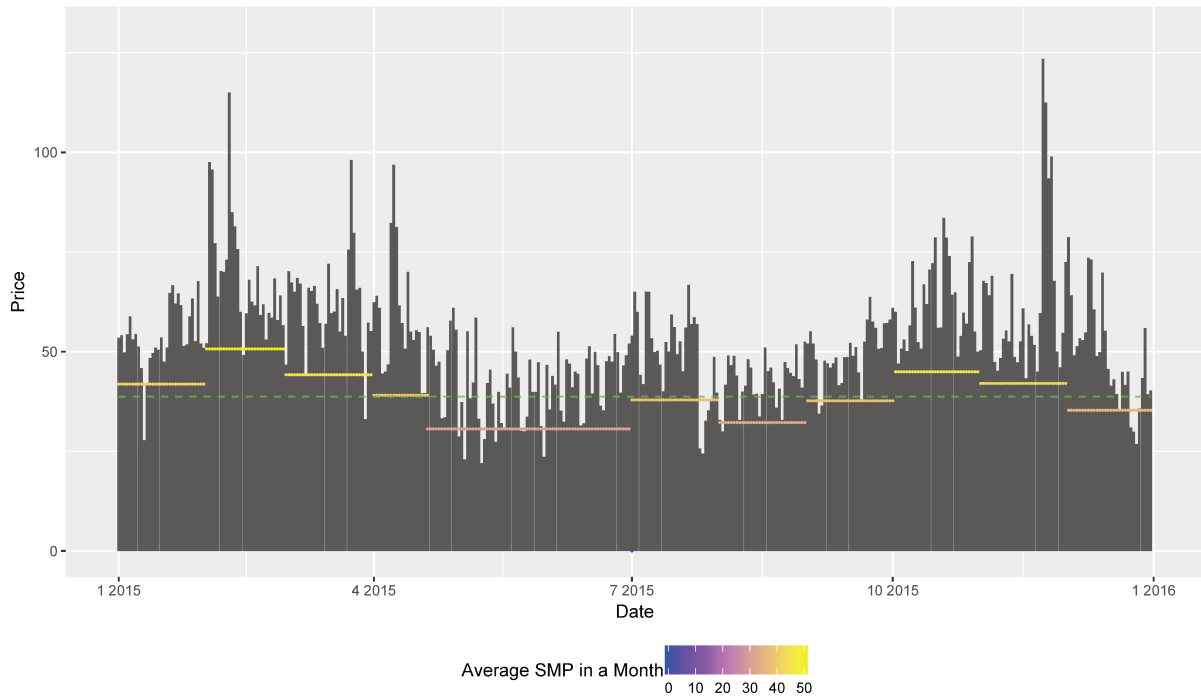


Figure A.30: SMP, France in 2015 (EUR(€)/MWh)

Source: "Prices - EPEX Spot Market Auction - France", EPEX, [On-line], Available: http://www.epexspot.com/fr/donnees_de_marche

Comparison to South Korea: Fig. A.28

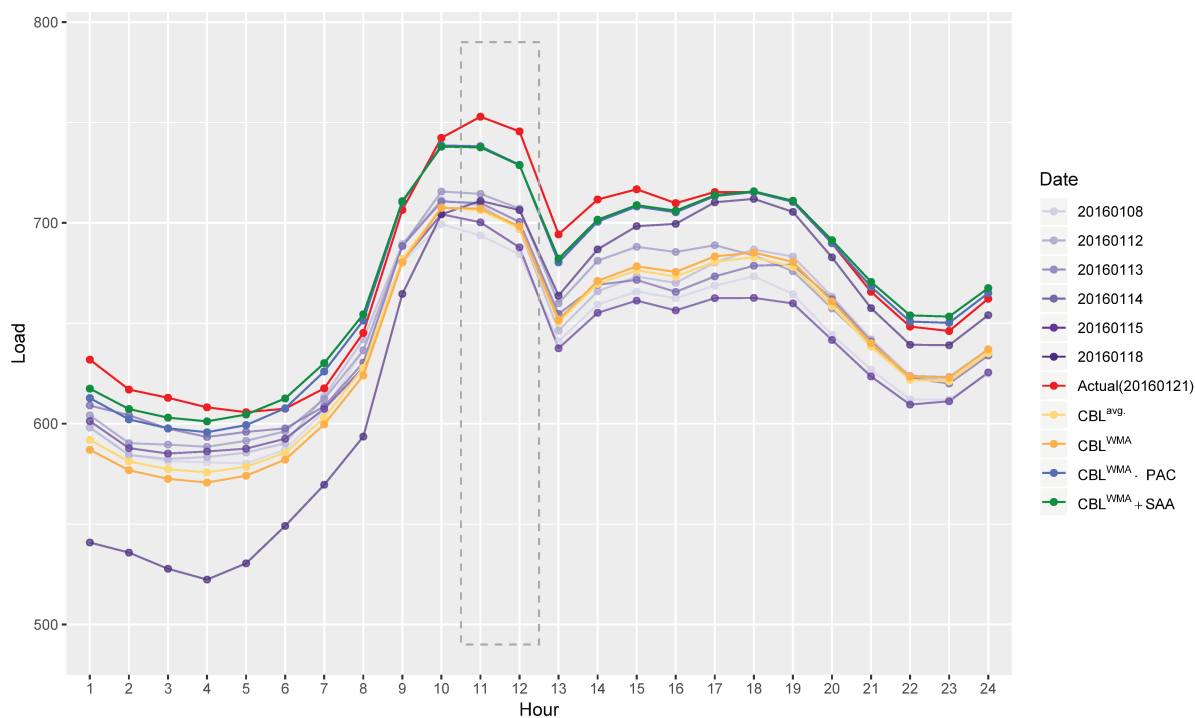


Figure A.31: The Visual Comparison among the CBLs Established with Different Methods (2016-01-21, South Korean DRTM) (W)

Source: The original load data before rescaling, “대국민 전력수급현황 공유 시스템” (Public Information Sharing System on Electricity Demand and Supply), KPX, [On-line], Available: <https://openapi.kpx.or.kr/sukub.do#>

Table A.9: Summary of the Established CBLs for the Event Times (2016-01-21, South Korean DRTM) (W)

	2016-01-21			
	...	11h	12h	...
Actual Load	...	752.88	745.54	...
CBL ^{avg}	...	706.32	697.16	...
CBL ^{WMA}	...	707.11	698.25	...
CBL ^{WMA} · PAC	...	738.16	728.91	...
CBL ^{WMA} + SAA	...	737.58	728.72	...

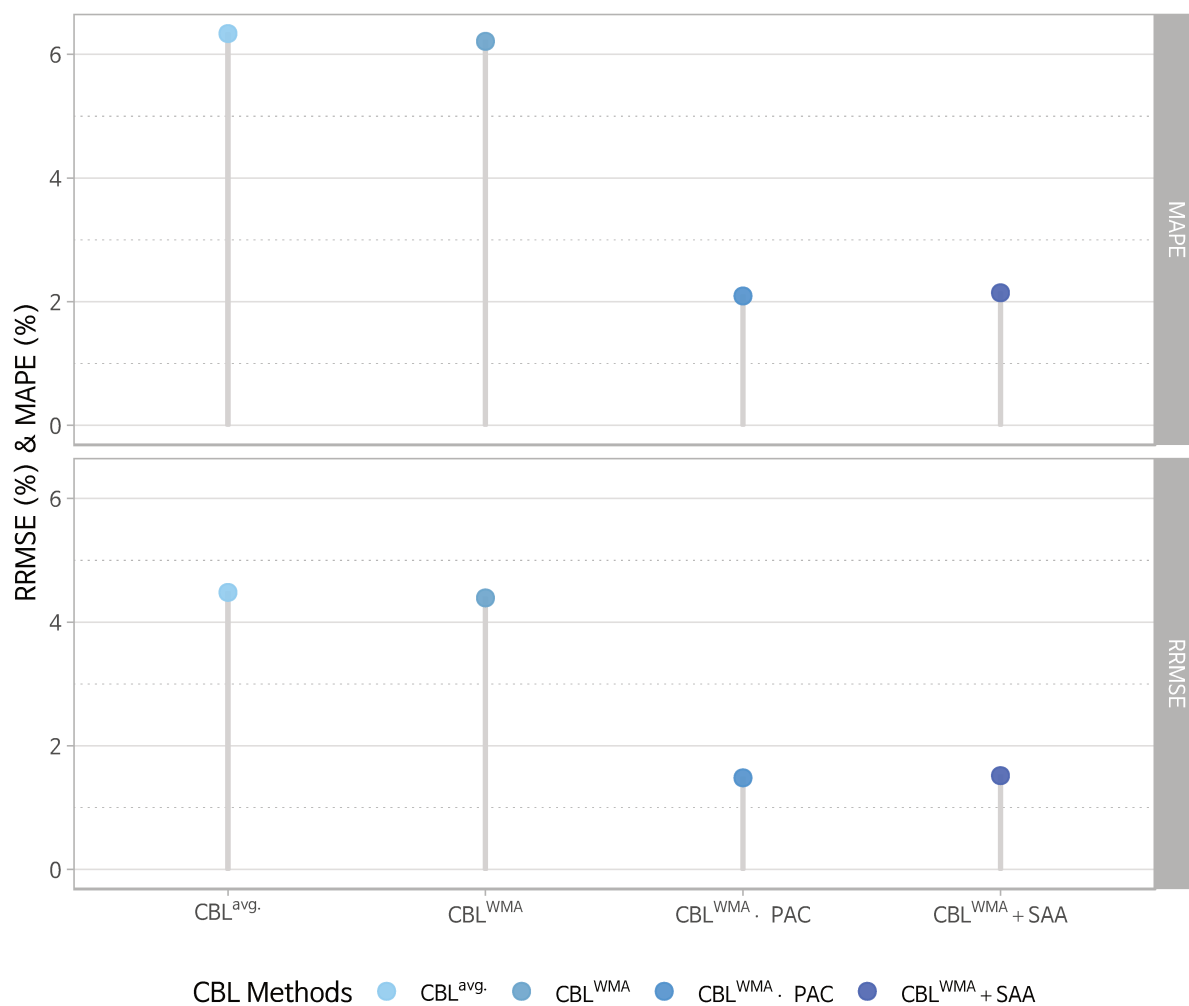


Figure A.32: The CBL Accuracy Comparison (MAPE & RRMSE) among the CBLs Established with Different Methods (2016-01-21, South Korean DRTM)

Table A.10: The CBL Accuracy Comparison (MAPE and RRMSE) among the CBLs Established with Different Methods (2016-01-21, South Korean DRTM)

	CBL ^{avg.}	CBL ^{WMA}	CBL ^{WMA} · PAC	CBL ^{WMA} + SAA
MAPE	6.34%	6.21%	2.09%	2.14%
RRMSE	4.48%	4.39%	1.48%	1.52%

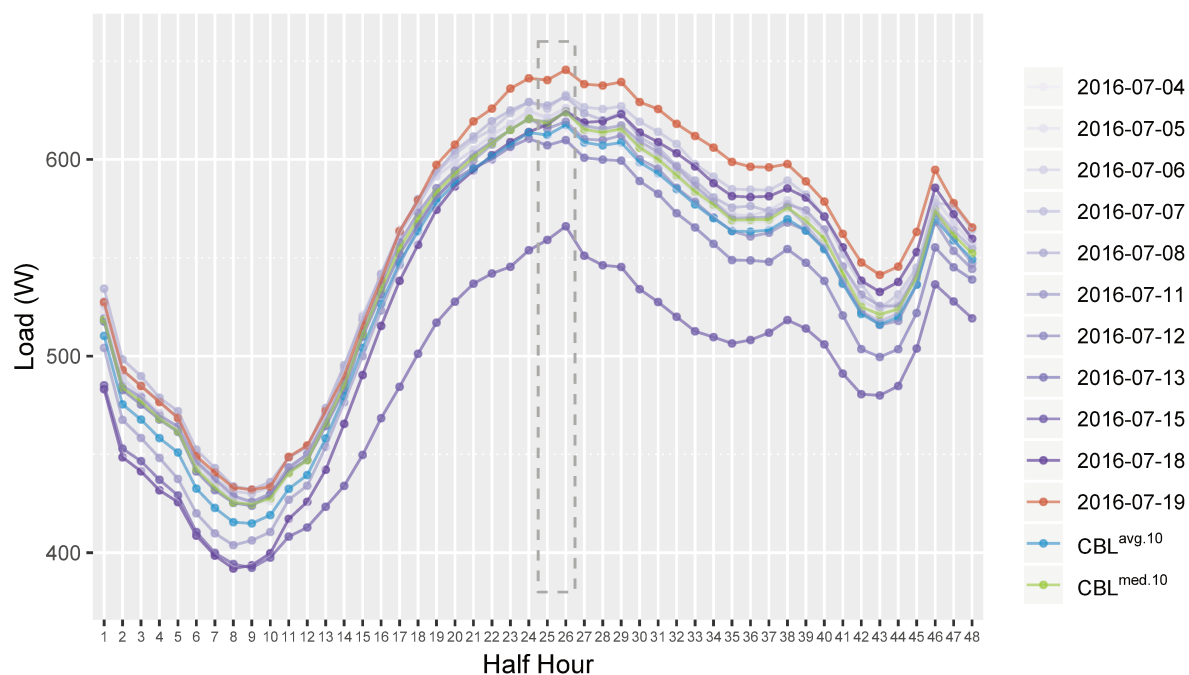


Figure A.33: The Visual Comparison among the Loads of the Previous Ten Days, Actual Loads, CBLs based on the Ten Day Average and Median Method (2016-07-19, French NEBEF) (W)

Source: The original load data before rescaling, RTE's PORTAIL CLIENTS, "Historique des consommations journalières en puissance", [On-line], Available: https://clients.rte-france.com/lang/fr/clients_traders_fournisseurs/vie/vie_stats_conso_inst.jsp

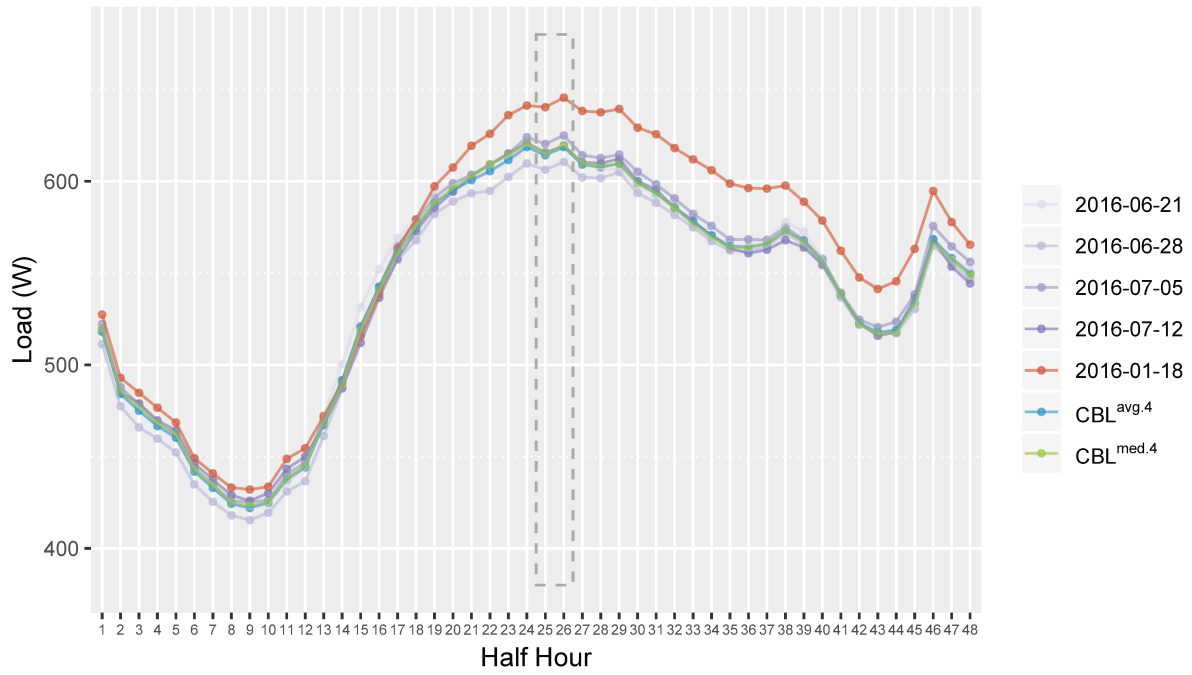


Figure A.34: The Visual Comparison among the Loads of the Previous Four Weeks, Actual Load, CBLs based on the Four Week Average and Median Method (2016-07-19, French NEBEF) (W)

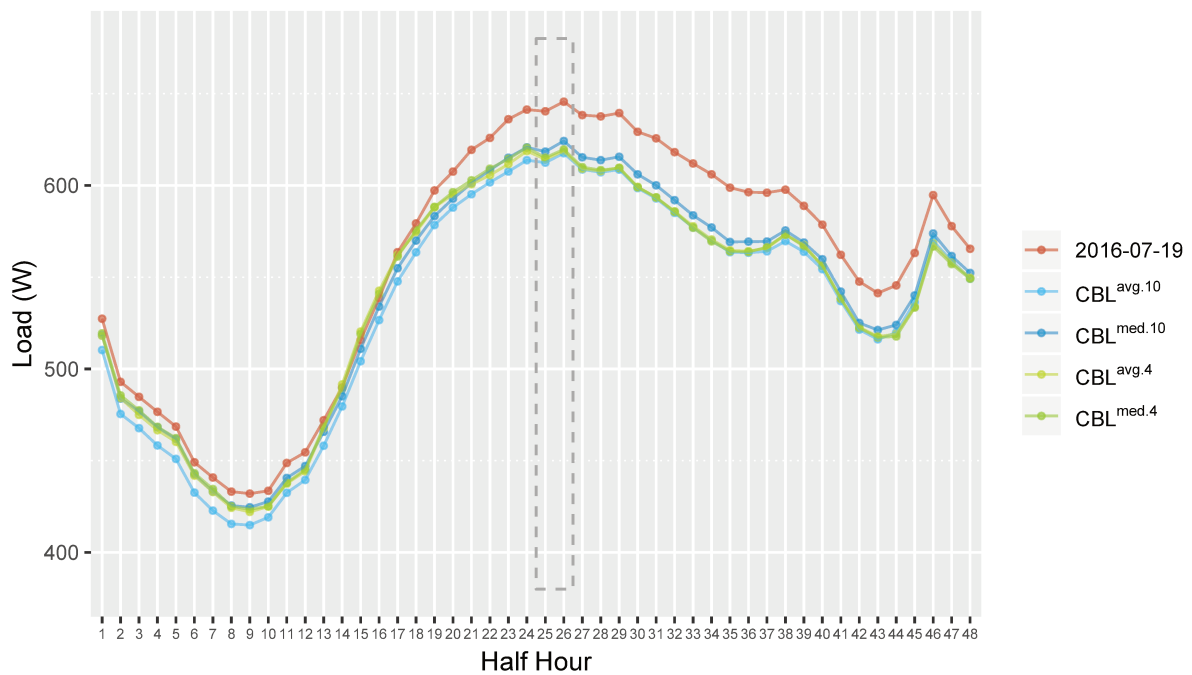


Figure A.35: Comparing the Actual Loads with all the Four CBLs (2016-07-19, French NEBEF) (W)

Table A.11: Summary of the Established CBLs for the NEBEF (DR) Event Times (2016-07-19, French NEBEF) (W)

2016-07-19				
	...	$t = 25$	$t = 26$...
Actual Load	...	640.39	645.59	...
$CBL^{avg.10}$...	612.40	617.53	...
$CBL^{med.10}$...	618.41	624.18	...
$CBL^{avg.4}$...	614.24	618.69	...
$CBL^{med.4}$...	615.15	619.62	...

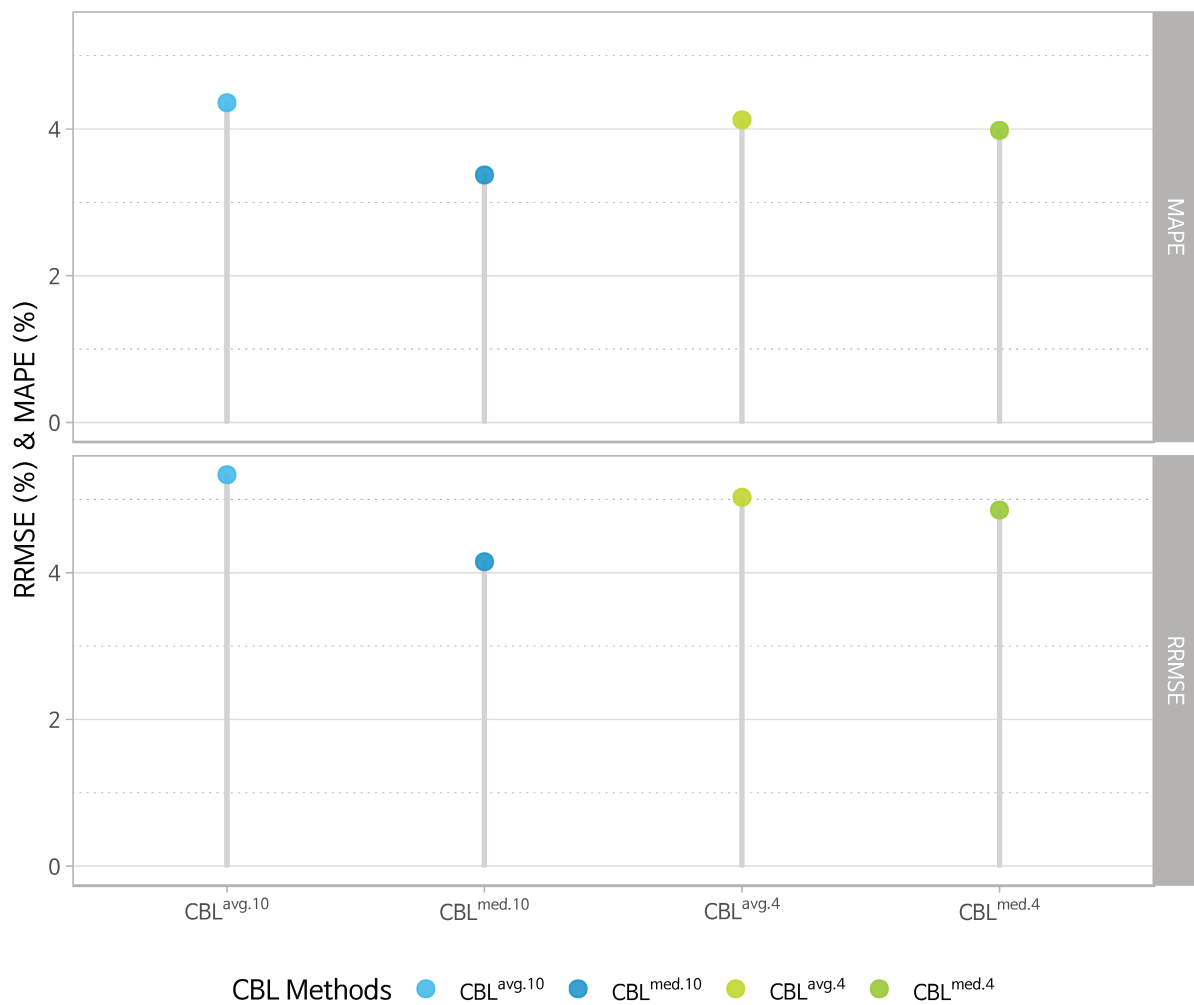


Figure A.36: The CBL Accuracy Comparison (MAPE & RRMSE) among the CBLs Established with Different Methods (2016-07-19, French NEBEF)

Table A.12: The CBL Accuracy Comparison (MAPE and RRMSE) among the CBLs Established with Different Methods (2016-07-19, French NEBEF)

	CBL ^{avg.10}	CBL ^{med.10}	CBL ^{avg.4}	CBL ^{med.4}
MAPE	4.36%	3.37%	4.13%	3.98%
RRMSE	5.34%	4.15%	5.03%	4.86%

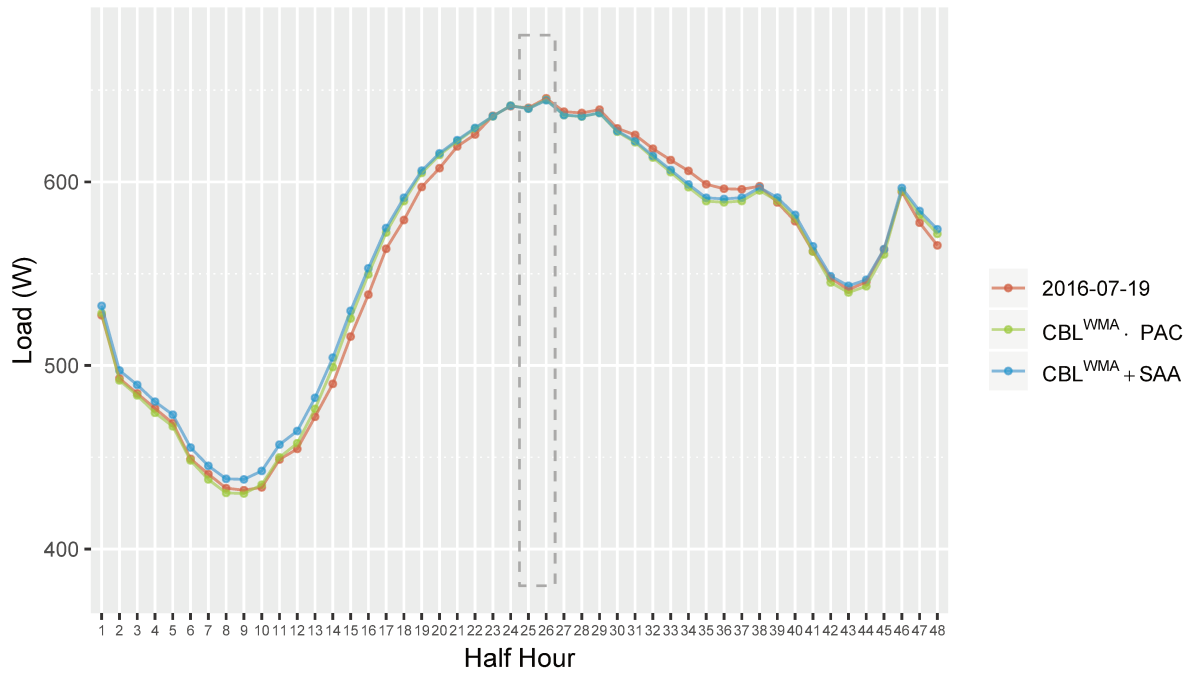


Figure A.37: Comparing the Actual Loads with the Two CBL Methods of CBL^{WMA} . PAC and CBL^{WMA} + SAA (2016-07-19, French NEBEF) (W)

Comparison to Four NEBEF CBL Methods: Fig. A.35

Table A.13: Summary of the Established CBLs for the NEBEF (DR) Event Times Applying CBL^{WMA} . PAC and CBL^{WMA} + SAA (2016-07-19, French NEBEF) (W)

	2016-07-19			
	...	$t = 25$	$t = 26$...
Actual Load	...	640.39	645.59	...
CBL ^{WMA} . PAC	...	639.98	644.78	...
CBL ^{WMA} + SAA	...	639.93	644.55	...

Comparison to Four NEBEF CBL Methods: Tab. A.11

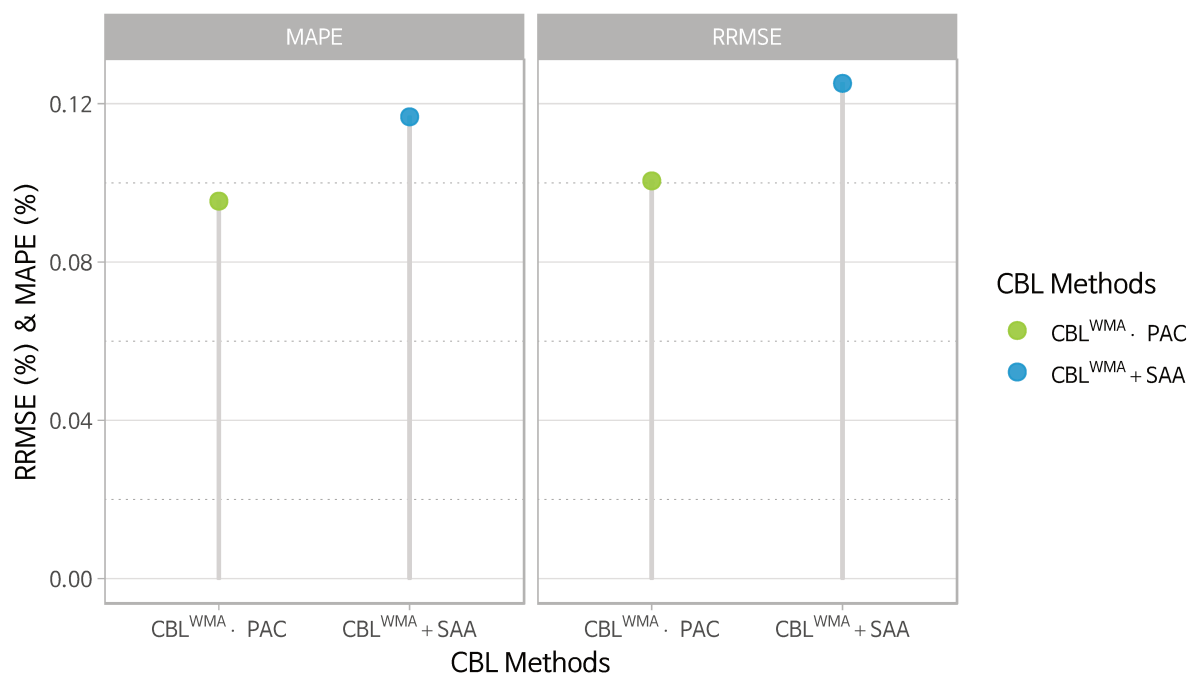


Figure A.38: The CBL Accuracy Comparison (MAPE & RRMSE) between the Two CBL Methods of $\text{CBL}^{\text{WMA}} \cdot \text{PAC}$ and $\text{CBL}^{\text{WMA}} + \text{SAA}$ (2016-07-19, French NEBEF)

Comparison to the Accuracies of Four NEBEF CBL Methods: Fig. A.36

Table A.14: The CBL Accuracy Comparison (MAPE and RRMSE) between the Two CBL Methods of $\text{CBL}^{\text{WMA}} \cdot \text{PAC}$ and $\text{CBL}^{\text{WMA}} + \text{SAA}$ (2016-07-19, French NEBEF)

	$\text{CBL}^{\text{WMA}} \cdot \text{PAC}$	$\text{CBL}^{\text{WMA}} + \text{SAA}$
MAPE	0.095%	0.117%
RRMSE	0.101%	0.125%

Comparison to the Accuracies of Four NEBEF CBL Methods: Tab. A.12

Table A.15: The Actual Load and Estimated CBL for the Event Day (W)

Date/Time	Actual Load	CBL(WMA+SAA)
2016-08-12	ℓ	$\text{CBL}^{\text{WMA}} + \text{SAA}$
t=01	576.62	583.79
t=02	548.89	567.77
t=03	546.87	565.81
t=04	546.18	565.55
t=05	543.93	567.35
t=06	548.57	569.84
t=07	566.75	584.34
t=08	602.67	617.45
t=09	665.97	675.74
t=10	718.88	722.67
t=11	743.98	747.10
t=12	754.83	758.58
t=13	727.38	738.55
t=14	756.96	763.11
t=15	772.37	773.57
t=16	771.58	770.39
t=17	774.60	770.63
t=18	763.83	760.80
t=19	739.30	743.08
t=20	728.48	737.07
t=21	713.71	726.36
t=22	679.94	697.63
t=23	646.38	664.35
t=24	623.48	643.05

Source: The original load data before rescaling, “대국민 전력수급현황 공유 시스템” (Public Information Sharing System on Electricity Demand and Supply), KPX, [On-line], Available: <https://openapi.kpx.or.kr/sukub.do#>

Table A.16: The Required Load Reduction Level and the Target Reduction on 20%, 30%, 40%, Max Level (W)

		2016-08-12				
		...	17h	18h	...	Sum
$\text{CBL}^{\text{WMA}} + \text{SAA}$...	770.63	760.80	...	1,531.43
Required Reduction Level						
20%	reduction	...	57.73	55.76	...	113.49
	remained	...	712.90	705.04	...	1,417.94
30%	reduction	...	86.59	83.64	...	170.23
	remained	...	684.04	677.16	...	1,361.20
40%	reduction	...	115.45	111.52	...	226.97
	remained	...	655.18	649.28	...	1,304.46
Maximum	reduction	...	288.63	278.80	...	567.43
	remained	...	482.00	482.00	...	1,531.43

Table A.17: The Target Load Reduction Level and the Target Reduction on 20%, 30%, 40%, Max Level (W)

		2016-01-18				
		...	$t = 37$	$t = 38$...	Sum
Actual Load		...	982.11	999.89	...	1,982.00
	CBL ^{avg.10}	...	861.60	878.36	...	1,739.96
MinBase		...	565.61	565.61	...	
Maximum Reducible Capacity		...	295.99	312.75	...	608.74
Target Reduction Level						
20%	reduction	...	59.20	62.55	...	121.75
	remained	...	802.41	815.81	...	1,618.22
30%	reduction	...	88.80	93.83	...	182.62
	remained	...	772.81	784.54	...	1,557.34
40%	reduction	...	118.40	125.10	...	243.50
	remained	...	743.21	753.26	...	1,496.47
Maximum	reduction	...	295.99	312.75	...	608.74
	remained	...	565.61	565.61	...	1,131.23

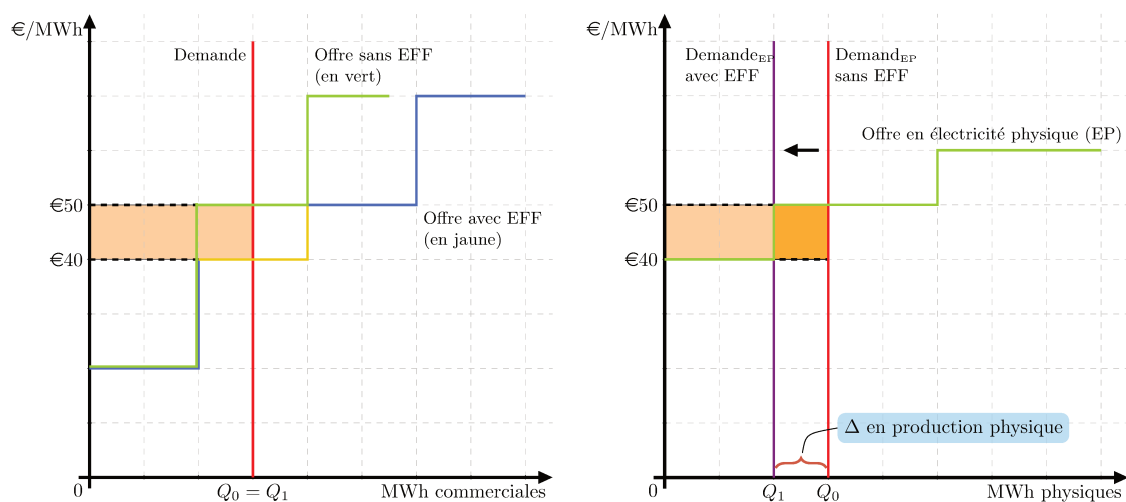
Appendix B: Résumé en français

L'Analyse Coûts-Bénéfices sur l'Effacement Résidentiel en se Basant sur l'Optimisation et Simulation : Applications aux Mécanismes de l'Effacement Français et Coréen

Chapitre 1 - Introduction: Demand d'électricité et rôle d'effacement

Dans ce chapitre 1, nous avons brièvement examiné l'idée générale et le contexte de l'introduction d'effacement. En particulier, comme nous avons examiné le contexte de l'introduction d'effacement en Corée du Sud, nous avons pu réaliser que dans quelle situation l'effacement est nécessaire et que dans quel contexte l'effacement jouera des rôles plus importants. Le contexte et les motivations plus détaillés de l'introduction d'effacement en Corée du Sud et en France seront expliqués au chapitre 2.

En plus du contexte dans la réalité, la logique théorique d'effacement en économie nous a fourni des explications plus élaborées sur les rôles et les impacts d'effacement sur le marché de l'électricité. Nous avons compris que si nous introduisons le régime tarifaire variant dans le temps, c'est-à-dire les *PBP (Price-based Programs)*, nous pouvons augmenter le bien-être social. De plus, comme nous proposons l'effacement sur le marché de gros et, en même temps, réduisons physiquement les charges d'électricité pendant les périodes de pointe, cela peut réduire les coûts marginaux d'approvisionnement en électricité et, à son tour, diminuer le prix de l'électricité (Graphique B.1). Cela a également un impact sur l'élasticité de la demande d'électricité ainsi que sur la sécurité de l'approvisionnement.



Graphique B.1: Analyse graphique de l'effacement en termes d'électricité commerciale (à gauche) et physique (à droite) avec demande inélastique et courbe d'ordre de mérite

Source: L'auteur, Seungman LEE, a recréé les graphiques originales dans la référence suivante. *ANALYSE ÉCONOMIQUE DES BENEFICES PRIVÉS ET PUBLICS EN TERMES DE CONSOMMATION ET PRODUCTION D'ÉNERGIE D'UN EFFACEMENT DANS LE CADRE DU NEBEF*, by [Kessler, 2014a](#).

Dans le cadre de la revue de la littérature, la définition d'effacement et les catégorisations de la maîtrise de la demande d'électricité et l'effacement ont clarifié notre compréhension d'effacement et les distinctions avec d'autres concepts, tels que l'efficacité énergétique, le réseau intelligent. De plus, cette catégorisation a permis de clarifier le positionnement du sujet de cette recherche et d'en affiner la portée.

Nous avons constaté que l'effacement présente de nombreux avantages à bien des égards. Il peut augmenter l'efficacité du système électrique à mesure que l'effacement diminue les installations de capacité inutiles et les ressources associées. En outre, l'effacement améliore la sécurité de l'approvisionnement en réduisant les charges de pointe. La réduction des charges pendant les périodes de pointe signifie plus de flexibilité pour les opérateurs du système. De plus, comme l'effacement dissuade les extensions de capacité supplémentaires, nous pouvons éviter les coûts supplémentaires de transport et de distribution. Tous ces effets entraînent des avantages environnementaux, tels que moins d'émissions de gaz à l'effet de serre, moins de centrales électriques et moins d'installations de transmission et de distribution. Enfin, l'effacement est utile pour une intégration plus facile des [énergies renouvelables à apports variables \(EnRv\)](#).

Cependant, nous avons également précisé les défis à relever pour faire bon usage d'effacement. De nos jours, les problèmes technologiques sont moins problématiques, mais le cadre et la conception du marché, ainsi que les analyses coûts-bénéfices rationnelles pour les programmes d'effacement devraient être davantage traités. Ces questions ont offert les motivations de cette recherche.

L'objectif ultime de la recherche est de fournir aux entités liées au programme d'effacement, en particulier les opérateurs de système d'effacement, un cadre décisionnel basé sur l'analyse coûts-avantages dans laquelle l'optimisation (programmation linéaire) est utilisée afin de représenter la rationalité de les participants de l'effacement, et de fournir des explications microéconomiques sur les comportements des participants de l'effacement. En d'autres termes, nous allons déterminer dans quelles conditions ou circonstances un client résidentiel participe à un programme d'effacement, combien de charges le client réduit-il ou à quelle plage horaire le client modifie-t-il les consommations d'électricité afin de minimiser les coûts. De plus, afin de prendre en considération toutes les variations possibles en termes de variables clés, la méthode de simula-

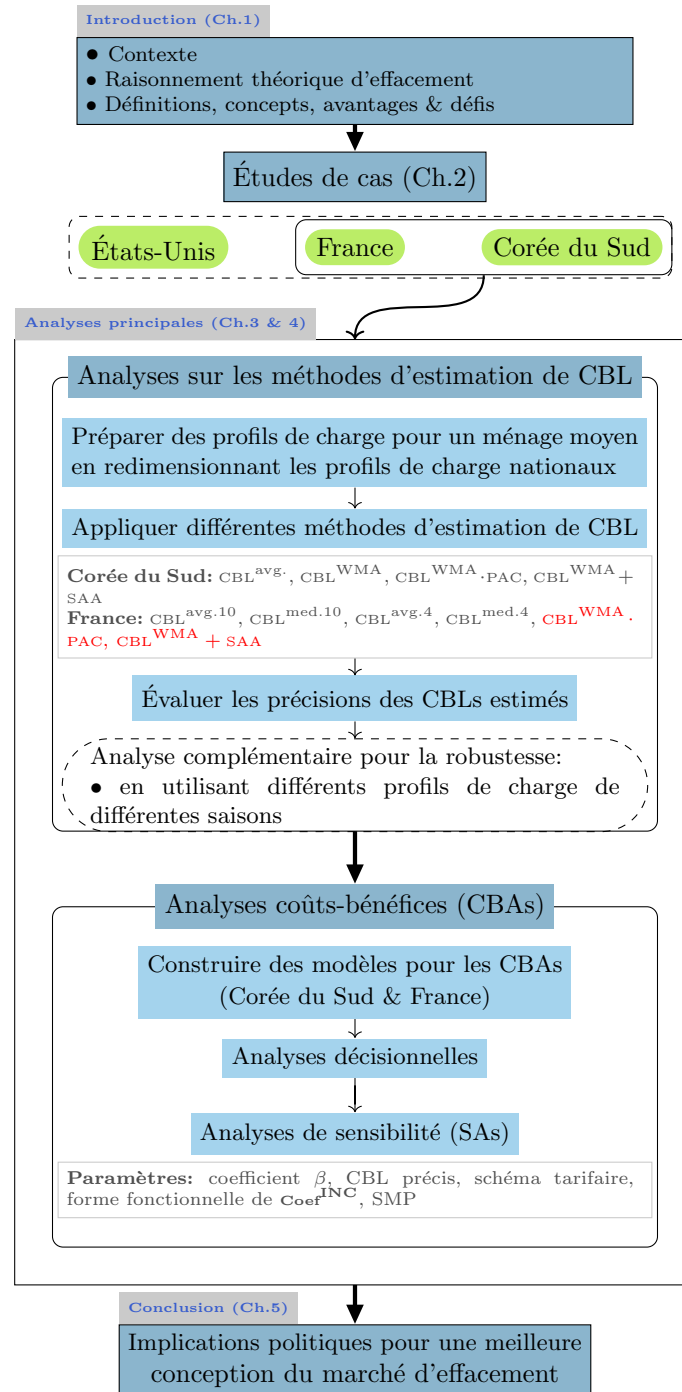
tion de Monte Carlo sera utilisée à la fois pour l'analyse décisionnelle basée sur l'analyse coûts-bénéfices et son analyse de sensibilité. De plus, pour des raisons de commodité concernant de vastes données et un certain nombre de répétitions de calcul, l'algèbre matricielle (algèbre linéaire) est utilisée ainsi que l'arithmétique. En fin de compte, sur la base des analyses coûts-bénéfices, des analyses décisionnelles et des analyses de sensibilité, nous allons tirer des implications politiques pour une meilleure conception du marché de l'effacement à la fois pour la Corée du Sud et la France.

Le Tableau B.1 suivant résume les sources des données utilisés dans les analyses des méthodes d'estimation des courbes de référence dans chapitre 3 et les analyses coûts-bénéfices au chapitre 4.

Tableau B.1: Résumé des sources des données utilisées dans les analyses des méthodes d'estimation des CBLs et les CBAs

	Corée du Sud	France
Charge	KPX	ENTSO-E
Informations sur clients résidentiels: proportion, nombre	"Electricity Big Data Center" chez KEPCO	RTE; CRE; Enedis
Données & statistiques sur programmes d'effacement SMP	"Electric Power Market Statistics" chez KPX	"PORTAIL CLIENTS" chez RTE
Régime tarifaire (prix)	KEPCO; "EPSIS" chez KPX	IEA; EDF
Autres informations sur la production d'électricité & consommation	IEA; "PRIS" chez IAEA	IEA; "PRIS" chez IAEA

Cette thèse est structurée comme suit (Graphique B.2). Au chapitre 1, le contexte et le raisonnement théorique de l'effacement sont expliqués, et les objectifs et la portée de la recherche sont présentés. De plus, en examinant les études précédentes sur la maîtrise de la demande d'électricité et l'effacement, de nombreux concepts étroitement liés seront traités ainsi que les avantages et les défis de l'effacement. Avant les analyses sur les méthodes d'estimation des courbes de référence et les analyses coûts-bénéfices, de brèves études de cas seront réalisées pour les États-Unis, la France et la Corée du Sud au chapitre 2. Au chapitre 3, les courbes de référence expérimentales seront établies et des analyses sur les différentes méthodes d'estimation des courbes de référence seront effectuées. De plus, afin de garantir la robustesse de l'analyse sur les méthodes d'estimation des courbes de référence, la même analyse sera effectuée avec les différents profils de charge des différentes saisons. Au chapitre 4, les modèles de l'analyse coûts-bénéfices seront construits en utilisant l'algèbre linéaire, la programmation linéaire pour l'optimisation et les simulations de Monte Carlo, et la méthodologie pour l'analyse décisionnelle sera présentée. Après une enquête approfondie sur les résultats des analyses coûts-avantages et des analyses décisionnelles, les analyses de sensibilité seront effectuées afin de couvrir différentes conditions pour un modèle de marché de l'effacement donné. Enfin, dans le chapitre 5, en tenant compte des résultats et des discussions, des implications politiques significatives seront tirées pour une meilleure conception du marché de l'effacement en termes de méthodes d'estimation des courbes de référence précises et d'autres facteurs clés des mécanismes de l'effacement.



Graphique B.2: Déroulement de la recherche

Chapitre 2 - Cas d'étude: États-Unis, France et Corée du Sud

Dans ce chapitre 2, nous avons passé en revue la brève histoire et la tendance de la maîtrise de la demande d'électricité et d'effacement aux États-Unis. Nous avons constaté que les États-Unis étaient le premier moteur depuis les années 1970 et sont maintenant le premier pays en termes d'effacement [selon le rapport

de *Transparency Market Research*, récitation de (Paterakis et al., 2017, p. 878)]. Dans le chapitre 1, comme nous avons constaté que l'un des obstacles à l'effacement était le manque de réglementations appropriées sur l'effacement en Europe, et contrairement à l'Europe, les États-Unis pourraient très bien définir les réglementations nécessaires pour introduire des programmes de la maîtrise de la demande d'électricité et l'effacement sur le marché de l'électricité très tôt. Ces règlements clairs sont le résultat du solide soutien et des initiatives du gouvernement en faveur d'effacement. En conséquence, ces jours-ci, nous pouvons observer les programmes florissants d'effacement et ses performances dans tous les principaux États, tels que la Californie, le Texas, New York, les régions PJM, etc. Comme les États-Unis ont mis en œuvre plus de programmes d'effacement activement, il a été possible d'accumuler les expériences et de confirmer le potentiel d'effacement en tant que ressources de fiabilité et de flexibilité.

La France, en tant qu'un des États membres de l'UE, est également en train de devenir un pays très actif pour l'effacement avec le Royaume-Uni, la Belgique, la Suisse, l'Irlande et la Finlande. Il semble que le pic historique de la demande en 2012 ait été une sorte de choc pour les Français, et depuis lors, ils sont plus préoccupés par des mesures plus sûres pour garantir la fiabilité et la flexibilité du système, en particulier pour l'hiver extrêmement froid. La part croissante des énergies renouvelables, son intégration harmonieuse au système électrique et les préoccupations relatives au changement climatique ont également été à l'origine de l'introduction du mécanisme NEBEF et de l'ouverture complète des marchés pour les ressources du côté de la demande. On pourrait y trouver, la pleine ouverture des marchés des ressources du côté de la demande, un point fort du système électrique français.

En examinant les évolutions du mécanisme NEBEF, nous avons pu observer les tendances à l'amélioration des performances. De plus, nous avons pu vérifier les schémas d'activation de NEBEF ainsi que les schémas de consommation d'électricité, c'est-à-dire la courbe de charge. En examinant la courbe de charge indiquée par NEBEF, il est possible de conclure que NEBEF devrait être plus activé pendant les périodes de pointe, en particulier en hiver, afin d'atteindre l'objectif intrinsèque d'effacement—c'est-à-dire réduire les charges de pointe, et, à son tour, garantissant la fiabilité, l'efficacité, l'abordabilité et la durabilité du système. En d'autres termes, ces observations nous ont fourni quelques indices pour cette recherche afin d'améliorer la performance du NEBEF, nous devons désormais mettre davantage l'accent sur le secteur résidentiel, les réductions de charge par les participants résidentiels devraient être encouragées pendant le pic périodes, ce qui se produit généralement à 19 heures, et qu'à cette fin, la conception du marché du mécanisme NEBEF devrait être améliorée de manière à accroître les motivations des clients à y participer.

En ce qui concerne le marché d'effacement de la Corée du Sud (DRTM, Demand Response Trading Market), la motivation essentielle pour promouvoir l'effacement et introduire le mécanisme d'effacement orienté vers le marché était la fiabilité et la sécurité de l'approvisionnement. Comme l'expérience de la charge de pointe historique en 2012, France, les expériences de panne de courant rotative sans précédent en 2014 et les inconvénients qu'ils ont subis pendant les étés extrêmement chauds ont été les causes directes de considérer l'effacement comme l'une des mesures alternatives pour faire face aux circonstances instables et peu fiables de la Corée du Sud. En outre, les récentes politiques énergétiques du gouvernement sur l'élimination nucléaire, la fermeture des centrales au charbon vieillissantes, davantage d'énergies renouvelables ont rendu la situation plus adaptée à la promotion d'effacement.

Comme nous avons vérifié la heatmap des charges de la Corée du Sud, nous pouvons nous attendre à ce que l'effacement joue un rôle plus important tout au long de l'année, en particulier pendant les deux périodes de pointe en été et en hiver, car il y a deux périodes de pointe en Corée du Sud, contrairement à la France. On pourrait remarquer que le marché d'effacement de la Corée du Sud se comporte très bien en termes de capacité enregistrée et de réductions totales même s'il s'agit d'un tout nouveau mécanisme en Corée du Sud. Le fort soutien du gouvernement sud-coréen pourrait être l'une des raisons de cette grande performance de le marché d'effacement de la Corée du Sud. Cependant, nous avons également remarqué qu'il n'y avait pas encore de participant résidentiel dans la composition des participants en 2014, 2015 et 2016 car jusqu'à présent, le principal objectif du marché d'effacement de la Corée du Sud était les participants industriels et commerciaux, ce qui n'était pas très encourageant pour les clients résidentiels. On s'attend à ce que le gouvernement sud-coréen lance le plan du 'marché d'effacement de la Corée du Sud pour tous les citoyens' et la tarification

selon l'heure d'utilisation (ToU, Time-of-Use) pour les clients résidentiels, il y aura une participation active des clients résidentiels. Cette recherche se prépare à ce genre de situation dans un avenir très proche en Corée du Sud.

Les comparaisons des marchés de l'électricité (Tableau B.2) et des mécanismes d'effacement (Tableau B.3) entre la France et la Corée du Sud nous fourniraient les informations détaillées et fondamentales pour les analyses suivantes sur les méthodes d'estimation des courbes de référence, les analyses coûts-bénéfices, les analyses décisionnelles et les analyses sensibilité. Étant donné que les ressources du côté de la demande ne sont échangées que sur le marché de gros en Corée du Sud, nous ne pouvons pas analyser les ressources du côté de la demande échangées sur le marché des capacités, le marché auxiliaire ou le marché des réserves en France individuellement. Par conséquent, nous nous concentrons uniquement sur le mécanisme d'effacement orienté vers le marché et les ressources du côté de la demande échangées sur le marché de gros, c'est-à-dire NEBEF en France et le marché d'effacement de la Corée du Sud. Nous devons également noter que même si ces deux mécanismes d'effacement semblent avoir des natures similaires, orientés vers le marché et que les ressources sont échangées sur le marché de gros, NEBEF et le marché d'effacement de la Corée du Sud ne sont pas totalement basés sur les mêmes structures de marché de l'électricité. Par conséquent, nous devons prendre en compte ces différences pendant que nous effectuons les analyses suivantes dans les chapitres 3 et 4 tout en conservant la simplicité des analyses.

Tableau B.2: Comparaisons des structures des marchés de l'électricité entres France et Corée du Sud

	France	Corée du Sud
des marchés en cours		
marché du jour d'avant	o	o
marché intrajournalier	o	o
marché des capacités	o	x
marché des services auxiliaires	o	o (services)
marché des réserves (marché d'équilibrage)	o	o (services)
plateforme	EPEX enchère de prix	KPX CBP
opérateur système	RTE (société mère: EDF)	KPX
nature du marché	concurrent, pas intégré verticalement, très concentré,	pas très concurrent, intégré verticalement,
régulateur ou régulatrice	CRE	MOTIE
acteur principal	EDF, quasi-monopole	KEPCO, monopole

Tableau B.3: Comparaisons des mécanismes d'effacement entre France et Corée du Sud

	France	Corée du Sud
mécanisme principal	NEBEF	DRTM
opérateur principal	RTE	KPX
depuis	décembre, 2013 (phase de test: déc. 2013–déc. 2014)	décembre, 2014
objectifs	abordabilité, durabilité, sécurité d'approvisionnement, intégration des EnR,	fiabilité, sécurité d'approvisionnement, politique environnementale, moteurs de la croissance économique,
marchés possibles pour la participation		
marché du jour d'avant	o	o
marché intrajournalier	o (depuis janv. 2017)	o
marché des capacités	o	inexistence
marché des services auxiliaires	o	inexistence
marché des réserves (marché d'équilibrage)	o	inexistence
méthodes des courbes de référence	day-matching simple, moyenne et médian	day-matching avec WMA & l'options d'ajustement
rémunération	(SMP-Versement)	SMP

Chapitre 3 - Estimation de la courbe de référence

Au chapitre 3, nous avons constaté que les méthodes d'estimation des courbes de référence du marché d'effacement de la Corée du Sud, en particulier les deux méthodes d'estimation de $CBL^{WMA} \cdot PAC$ et $CBL^{WMA} + SAA$, fonctionnent étonnamment très bien avec des taux d'erreur extrêmement faibles d'environ 0,5% tandis que toutes les méthodes d'estimation des courbes de référence de NEBEF ne fonctionnent pas très bien avec des taux d'erreur élevés d'environ 12%–25%. De plus, lorsque nous avons appliqué les deux méthodes d'estimation des courbes de référence de $CBL^{WMA} \cdot PAC$ et $CBL^{WMA} + SAA$ au profil de charge moyenne des ménages français mis à l'échelle pour établir la courbe de référence, cela a abouti à une performance élevée avec des taux d'erreur extrêmement faibles inférieurs à 0,5%. Il est intéressant et, en même temps, surprenant que cette simple méthode d'estimation statistique des courbes de référence d'appariement journalier avec une option soit suffisante. En d'autres termes, des méthodes très complexes et avancées et un large éventail de données ne sont pas essentiels dans ce cas.

De plus, les résultats des analyses complémentaires sur les différents profils de charge de différentes saisons sont en ligne avec les principaux résultats reconfirmant que les deux méthodes d'estimation des courbes de référence avec ajustement ($CBL^{WMA} \cdot PAC$ et $CBL^{WMA} + SAA$) sont les meilleurs même si les profils de chargement sont plus stochastiques et volatile. Par conséquent, cette validation croisée entre différentes saisons dans un pays a ajouté la robustesse de la recherche. Avec les résultats, cette étude fournit à un pays, en particulier la France, une implication politique significative pour améliorer les méthodes d'estimation des courbes de référence de NEBEF et, finalement, la conception du marché d'effacement. Le Tableau B.4 suivant résume les résultats de la précision des méthodes d'estimation des courbes de référence en termes de MAPE et RRMSE.

Les cellules grises mettent en évidence la meilleure méthode d'estimation des courbes de référence avec le plus petit taux d'erreur.

Tableau B.4: Aperçu des résultats: précision des méthodes d'estimation des courbes de référence (MAPE & RRMSE)

	Corée du Sud				France			
	été		hiver		été		hiver	
	2016-08-12		2016-01-21		2016-07-19		2016-01-18	
	MAPE	RRMSE	MAPE	RRMSE	MAPE	RRMSE	MAPE	RRMSE
CBL ^{avg.}	9.21%	6.51%	6.34%	4.48%				
CBL ^{WMA}	8.22%	5.81%	6.21%	4.39%				
CBL ^{WMA} · PAC	0.52%	0.37%	2.09%	1.48%	0.095%	0.101%	0.418%	0.437%
CBL ^{WMA} + SAA	0.45%	0.32%	2.14%	1.52%	0.117%	0.125%	0.245%	0.246%
CBL ^{avg.10}					4.36%	5.34%	12.21%	14.94%
CBL ^{med.10}					3.37%	4.15%	13.30%	16.26%
CBL ^{avg.4}					4.13%	5.03%	20.34%	24.89%
CBL ^{med.4}					3.98%	4.86%	20.48%	25.03%

Comme le marché d'effacement de la Corée du Sud, le mécanisme NEBEF est un mécanisme de la maîtrise de la demande d'électricité orienté vers le marché assez récent, il évolue donc depuis les 'Règles NEBEF 1' en 2013. Même s'il semble que RTE (Réseau de transport d'électricité) ait testé de nombreuses méthodes d'estimation des courbes de référence depuis la phase expérimentale, par exemple, l'approche d'analyse des données du panel, il paraît que RTE n'a pas encore explicitement suggéré ou introduit les options alternatives comme le PAC (*Proportional Adjustment Coefficient*) et le SAA (*Symmetric Additive Adjustment*). Selon les résultats de cette recherche, les faibles performances et les taux d'erreur élevés des méthodes d'estimation des courbes de référence de NEBEF découlent du fait qu'elle ne repose que sur la moyenne et la médiane simples et n'utilise aucune option d'ajustement qui pourrait capturer les récents changements du profil de charge causé par quoi que ce soit un événement stochastique basé sur la température ou socio-économique.

Comme nous avons examiné les tendances en développement des mécanismes d'effacement sud-coréens et français en termes de volume et de fréquence au chapitre 2, l'importance du mécanisme NEBEF sera plus importante avec des énergies renouvelables à apports variables, la préoccupation sur le changement climatique, la durabilité, et la sécurité de l'approvisionnement d'électricité. Afin d'exploiter le mécanisme d'effacement à part entière en France, nous devons accorder plus d'attention à l'importance de méthodes d'estimation des courbes de référence précises, qui sont les éléments fondamentaux pour encourager les participants potentiels. Comme nous l'avons observé, les méthodes d'estimation des courbes de référence actuellement utilisées sont susceptibles d'entraîner une sous-estimation des courbes de référence, ce qui se traduit par une sous-appréciation des efforts ou des réductions réels. Ces méthodes des courbes de référence inexactes pourraient saper le mécanisme français de NEBEF malgré son avantage, comme l'ouverture de haut niveau de tous les marchés pour les ressources du côté de la demande que nous avons trouvée au chapitre 2.

En outre, il est prévu que les méthodes précises d'estimation des courbes de référence peuvent empêcher les participants de manipuler intentionnellement et malveillamment leurs courbe de référence. C'est un point assez important du point de vue de l'opérateur du système d'effacement ou de l'opérateur d'effacement. Si les méthodes d'estimation des courbes de référence sont très précises, alors les participants auront peu de place pour manipuler stratégiquement leurs courbe de référence afin d'être rémunérés beaucoup plus qu'ils ne devraient l'être. Ce n'est qu'avec ces méthodes d'estimation courbes de référence bien définies qui peuvent éviter la sous-estimation ou la surestimation en tant qu'erreur de mesure et les incitations stratégiques à compenser que l'optimalité des programmes d'effacement peut être garantie.

Compte tenu des implications politiques susmentionnées, cette étude offre une bonne occasion de mettre en lumière et de comparer les méthodes d'estimation des courbes de référence de la Corée du Sud et de la France. Il est rare de voir ce type d'analyse comparative entre pays se concentrant sur les méthodes d'estimation des courbes de référence dans la pratique. L'une des difficultés pour mener ce type de recherche est qu'il n'est pas facile d'obtenir les profils de charge en temps réel d'un ménage individuel en raison des problèmes de confidentialité ou d'accès à l'information. L'approche dans laquelle nous avons utilisé le profil de charge redimensionné à partir des charges nationales agrégées a permis cette analyse. De plus, le modèle mathématique simple de l'algèbre linéaire a permis de comprendre clairement et plus facilement le processus de calcul des courbes de référence et son analyse. Bien que cette approche et le modèle mathématique simple de l'algèbre linéaire aient été appliqués au mécanisme d'effacement résidentiel, ils peuvent être appliqués à d'autres secteurs, tels que les programmes d'effacement industriels et commerciaux, car l'approche et le modèle utilisés dans cette recherche sont très génériques. Les termes très clairs et distincts, les équations et explications simples mais détaillées seront utiles pour de nouvelles études sur les courbes de référence dans de nombreux pays qui développent activement des mécanismes d'effacement.

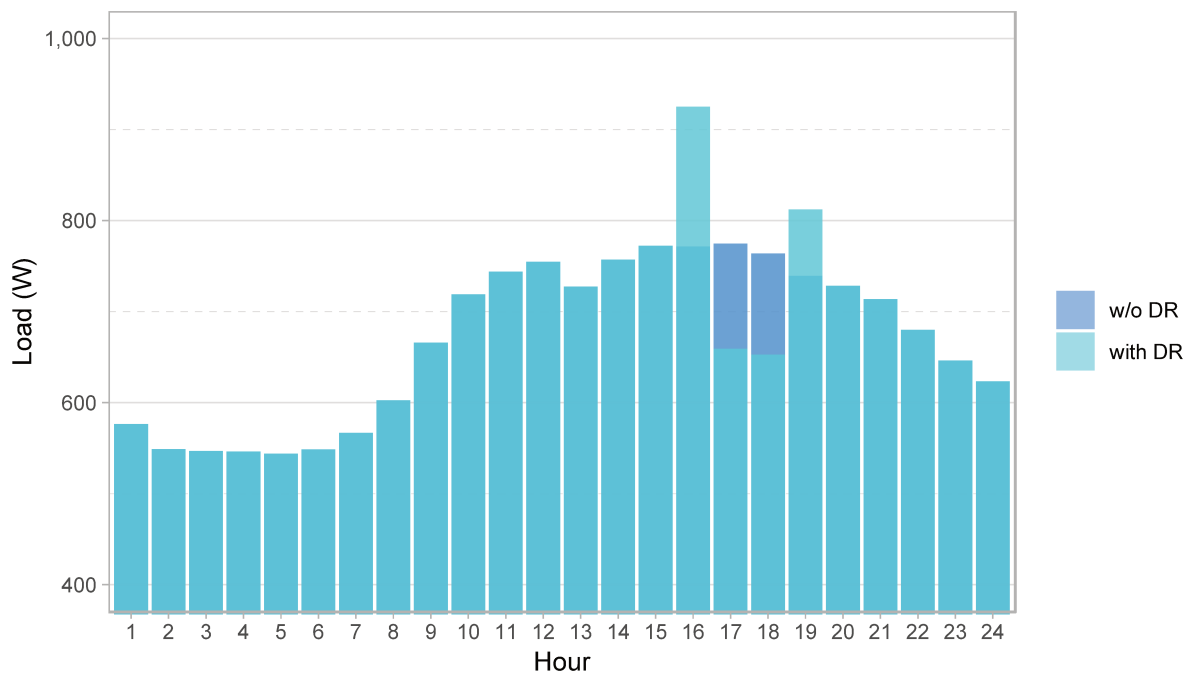
En plus de cela, cette étude et les courbes de référence estimées seront un tremplin ou une fondation pour les analyses suivantes, telles que l'analyse décisionnelle basée sur les courbes de référence et l'analyse de sensibilité dans le chapitre 4. Sans cette partie sur les courbes de référence, il sera presque impossible de poursuivre les recherches ou sera confronté à l'ambiguïté des mécanismes d'effacement. Uniquement sur la base des courbes de référence estimées avec précision, de la réduction de charge réelle, du niveau de rémunération optimal, de la désutilité marginale pour les participants avec l'effacement et le report de consommation, changement de comportement des participants (profil de consommation d'électricité avec l'effacement), de l'efficacité de la tarification selon l'heure d'utilisation, etc. peuvent être traités de manière appropriée.

Chapitre 4 - Analyse coûts-bénéfices sur l'effacement

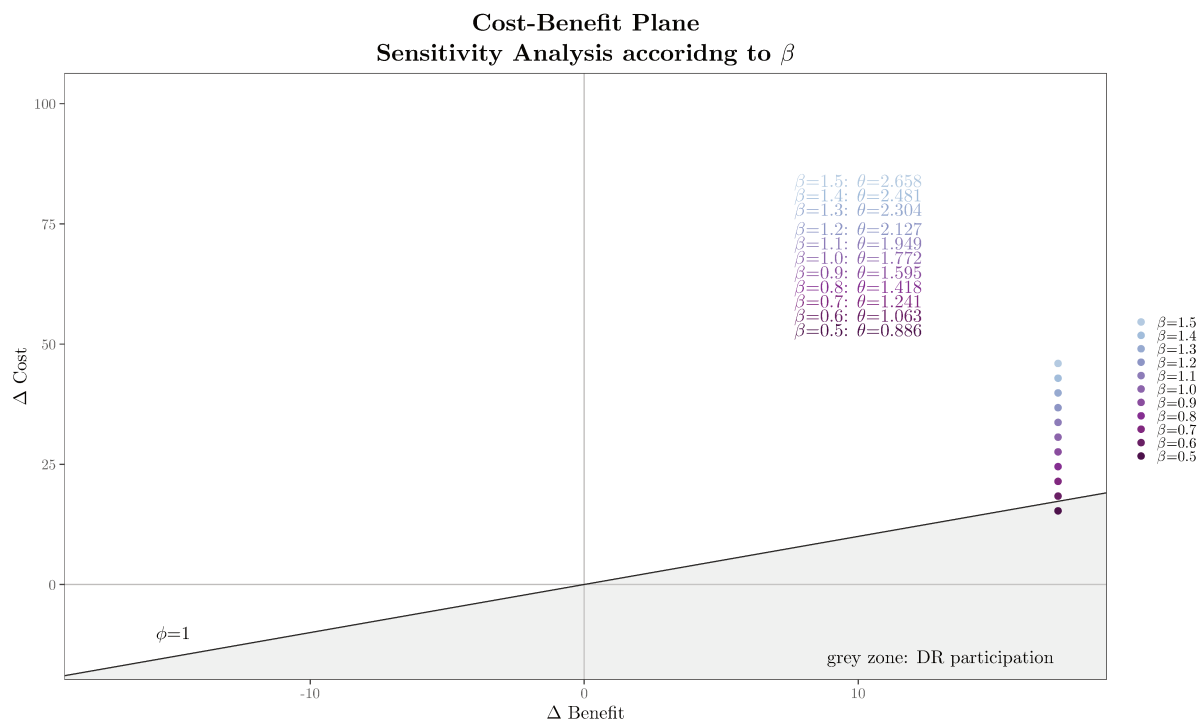
Dans ce chapitre 4, nous avons effectué des analyses coûts-bénéfices, des analyses décisionnelles et des analyses de sensibilité sur la base des courbes de référence établies dans le chapitre précédent 3. Lors de la construction du modèle des analyses coûts-bénéfices, nous avons pu reconfirmer mathématiquement et systématiquement l'importance de méthodes d'estimation des courbes de référence précises (Eq. 4.13). Ceci est conforme au résultat de l'étude précédente sur les méthodes d'estimation des courbes de référence au chapitre 3. Si les méthodes d'estimation des courbes de référence sont inexactes, les charges réellement réduites d'un client résidentiel seront sous-estimées et le montant de la rémunération diminuera. En fin de compte, cela découragera la participation d'effacement du client résidentiel. Ce point a également été observé dans les analyses de sensibilité du cas français NEBEF dans lequel la méthode d'estimation des courbes de référence a été remplacée par la méthode d'estimation des courbes de référence utilisée en Corée du Sud. Avec la méthode d'estimation des courbes de référence inexacte CBL^{avg-10} , les avantages nets étaient trop minimes, mais avec la méthode d'estimation des courbes de référence précise $CBL^{WMA} + SAA$, nous avons observé le décalage horizontal significatif et positif avec des avantages nets accrus. De la part de l'opérateur du système d'effacement, la méthode d'estimation précise des courbes de référence pourrait empêcher la manipulation intentionnelle et malveillante des courbes de référence des participants à l'effacement—incitations compensatoires stratégiques. De plus, bien sûr, seulement si les courbes de référence sont bien définies, l'optimalité du programme d'effacement pourrait être garantie. Par conséquent, la méthode d'estimation des courbes de référence peut jouer un rôle important dans la prise de décision de la participation d'effacement, et le fonctionnement transparent et durable.

De plus, nous avons pu comprendre l'importance des degrés d'inconvénients supplémentaires (coefficient β) à la fois pour l'effacement et le report de consommation dans les analyses coûts-bénéfices et les analyses de sensibilité. Dans les analyses coûts-bénéfices, pour le cas sud-coréen, le client résidentiel a déplacé la réduction de charge requise juste avant et après les plages horaires de l'événement d'effacement (Graphique B.3). Elle est le résultat de l'optimisation des coûts (programmation linéaire) en tenant compte des coûts

d'inconvénients supplémentaires. De plus, dans les analyses de sensibilité pour le cas sud-coréen et français dans lesquels les impacts de la variation de la valeur β ont été examinés (Graphique B.4), car la valeur β augmente, les coûts augmentent et, par conséquent, un client résidentiel finit par décider de ne pas participer au programme d'effacement—ou d'aller beaucoup plus loin s'il n'était pas dans la zone de participation d'effacement au début. Ce résultat nous donne une implication politique significative que lorsqu'un opérateur de système d'effacement conçoit le marché d'effacement, il doit examiner attentivement les coûts ou les perceptions d'inconvénients supplémentaires objectifs ou subjectifs d'un client pour l'effacement et le report de consommation.



Graphique B.3: Comparaison de charge réalisée entre sans et avec participation de l'effacement (Wh, DRTM en Corée du Sud)



Graphique B.4: Analyse de sensibilité selon les valeurs de β (DRTM en Corée du Sud)

On a également pu observer qu'il y avait un très léger décalage vertical avec le changement du régime tarifaire. Cela signifie que s'il y a une très petite différence entre les prix des périodes de pointe et des périodes creuses, il n'y aurait pas de motivations importantes pour un client résidentiel à participer au programme d'effacement—en particulier, les programmes d'effacement basés sur les prix. Par conséquent, si un opérateur de système d'effacement souhaite promouvoir un programme d'effacement avec un schéma tarifaire implicite de ToU, il devrait y avoir une forte différenciation des prix entre la période de pointe et la période creuse.

Tout comme l'importance du coefficient β , l'importance de la forme fonctionnelle de coef^{INC} a été confirmée. Que la forme fonctionnelle d'un participant de coef^{INC} soit linéaire ou exponentielle a des impacts sur les coûts et, à son tour, cela pourrait changer la décision à quelle plage horaire le participant reportera les réductions de charge afin de minimiser les coûts d'inconvénients supplémentaires.

Nous avons également été témoins des impacts très importants du SMP (*System Marginal Price*) avec les SMP les plus élevés et les plus bas. C'est très naturel et conforme à l'objectif intrinsèque d'effacement—lorsqu'il y a une demande de pointe, le SMP est élevé et cela donne aux clients une plus grande motivation pour participer au programme d'effacement. En conséquence, il peut réduire la demande de pointe et atteindre la fiabilité avec cette flexibilité. C'est un point très important car l'avantage pour les participants est la fonction du SMP, même s'il s'agit du régime tarifaire uniforme, la participation d'effacement joue un rôle de lien entre le marché de gros et le marché de détail. Le régime tarifaire uniforme ne peut pas envoyer le véritable signal sur les coûts marginaux de la fourniture d'électricité, cependant, les participants d'effacement peuvent recevoir les informations sur les prix lorsqu'ils participent au mécanisme d'effacement. Par conséquent, l'effacement peut corriger le signal du marché déformé et augmenter l'efficacité du système électrique. Le Tableau B.5 suivant résume tous les résultats des analyses de sensibilité en fonction de chaque changement de paramètre clé.

Tableau B.5: Résumé des résultats des analyses de sensibilité

paramètres	Corée du Sud	France
β : 0, 5 \Rightarrow 0, 5-1, 5 par 0, 1	impacts significatifs: valeurs β entre 0, 6-1, 5, hors zone de participation, décalages verticaux vers le haut	l'effacement: impacts significatifs: valeurs β entre 1, 1-1, 5, hors zone de participation, décalages verticaux vers le haut le report: impacts significatifs: tous les points, hors zone de participation, décalages verticaux vers le haut
courbes de référence précises	pas besoin de cette analyse de sensibilité pour Corée du Sud	l'effacement: impacts significatifs: valeurs β de 1, 1 déplacé dans la zone de participation, décalages horizontaux vers la droite le report: impacts significatifs: mais tous les points, hors zone de participation de l'effacement, décalages horizontaux vers la droite
tarification: uniforme \Rightarrow ToU	petits impacts: β 0, 6 déplacé dans la zone de participation, décalages verticaux vers le bas	l'effacement: de minuscules impacts: décalages verticaux subtils le report: petits impacts: décalages verticaux
ToU basé sur CBL précis	pas besoin de cette analyse de sensibilité pour Corée du Sud	l'effacement: presque le même résultat avec l'analyses de sensibilité avec CBL précis le report: presque le même résultat avec l'analyses de sensibilité avec CBL précis, mais des décalages un peu diagonaux
Coef ^{INC} basé sur ToU: linéaire \Rightarrow exponentielle	gros impacts: tous les points, déplacés dans la zone de participation, décalages verticaux vers le bas	le report: petits impacts: tous les points, hors zone de participation, décalages verticaux vers le bas
différents SMP basé sur CBL précis: SMP les plus élevés & les plus bas	gros impacts: •SMP les plus élevés: valeurs β de 0, 6-0, 8, déplacé dans la zone de participation, décalages horizontaux vers la droite •SMP les plus bas: tous les points, hors zone de participation, décalages horizontaux vers la gauche	l'effacement: •SMP les plus élevés: impacts très significatifs: tous les points, dans la zone de participation, décalages horizontaux vers la droite •SMP les plus bas: impacts significatifs: valeurs β de 0, 8-1, 0 sorti de la zone de participation, décalages horizontaux vers la gauche le report: •SMP les plus élevés: impacts très significatifs: tous les points, dans la zone de participation, décalages horizontaux vers la droite •SMP les plus bas: impacts significatifs: tous les points, hors zone de participation, décalages horizontaux vers la gauche

En plus des analyses de sensibilité avec les SMP les plus élevés et les plus bas, nous avons également calculé les SMP de seuil afin qu'un participant résidentiel ait des avantages nets positifs ou égaux à zéro en fonction de chaque valeur β . Du point de vue du client résidentiel, ces seuils SMP peuvent être les critères de participation ou non au programme d'effacement. Par conséquent, pour les opérateurs d'effacement et les gestionnaires de systèmes d'effacement, ces SMP de seuil peuvent leur fournir les informations lorsqu'ils estiment les taux de participation pour une tranche de temps spécifique avec un SMP spécifique et un client résidentiel avec une valeur β spécifique.

En plus du SMP lui-même, lorsque nous comparons les deux différents mécanismes d'effacement de la Corée du Sud et de la France, l'importance du niveau approprié de rémunération a été soulignée. Contrairement au cas sud-coréen, dans le mécanisme français de NEBEF, une partie, c'est-à-dire 'Versement' v du SMP doit être transférée au fournisseur d'électricité, donc la rémunération finale pour les clients résidentiels sont trop négligeables pour les encourager à participer au programme d'effacement. La question, "Quel est le niveau idéal pour la rémunération d'effacement?", est une question qui nécessite une autre recherche approfondie, et il semble que *a priori* le cas français soit plus proche du niveau de rémunération d'effacement théoriquement idéal, mais le cas sud-coréen est plus encourageant pour les participants potentiels à l'effacement. Par conséquent, l'opérateur français d'effacement, RTE, pourrait prendre en considération le niveau de rémunération d'effacement pour le programme d'effacement durable.

Même si l'analyse coûts-bénéfices est absolument impérative pour un programme d'effacement, et que le modèle d'analyse coûts-bénéfices construit dans cette étude est assez simple, il n'existait pas jusqu'à présent ce type de modèle fondamental et de recherche. Faire bon usage du modèle mathématique explicite et simple de l'algèbre linéaire rend le mécanisme d'effacement ambigu simple et clair. Avec ce modèle mathématique simple, il a été possible de comprendre clairement les interactions entre une série de composants d'un mécanisme d'effacement, tels que des courbes de référence, capacité réductible maximale, réduction de charge requise, réduction de charge effectivement remplie, SMP, tarification, l'effacement et le report de consommation, les coûts d'inconvénients supplémentaires, etc.

L'art de ce modèle simple repose sur le fait que le processus d'analyse est continu depuis le tout début de l'estimation des courbes de référence, des analyses coûts-bénéfices, des analyses décisionnelles, puis enfin des analyses de sensibilité avec des concepts et des éléments assez cohérents. Par conséquent, l'ensemble de ce modèle fournit un package pour l'analyse d'un mécanisme d'effacement. Le modèle utilisé dans cette étude est également assez générique, ce qui signifie qu'il peut être appliqué à d'autres programmes d'effacement industriels ou commerciaux, ou dans d'autres pays où les gestionnaires de réseau envisagent d'introduire des programmes d'effacement.

Dans cette recherche, puisque nous nous sommes concentrés sur la demande de pointe et le potentiel d'effacement pour réduire la demande de pointe, nous avons supposé que les périodes d'événement d'effacement sont données. Mais ce n'est pas toujours le cas. Dans le cadre du programme d'effacement économique en Corée du Sud, DRTM et en France, NEBEF, les opérateurs d'effacement, au nom des participants, peuvent soumissionner des ressources côté de la demande à tout moment si cela est rentable pour eux et leurs clients. Leur prise de décision sur le créneau horaire auquel ils soumissionneront peut également être traitée en optimisation des coûts (programmation linéaire) en interne. Pour le programme de *Peak Reduction DR* au marché de l'effacement de la Corée du Sud, le modèle d'analyse coûts-bénéfices utilisé dans cette étude est suffisant, mais pour le programme *Economic DR* au marché de l'effacement de la Corée du Sud et NEBEF, il a besoin de ce type d'extension du modèle d'analyse coûts-bénéfices.

Dans un contexte similaire, dans ces analyses coûts-bénéfices, j'ai choisi les jours de pointe pour la journée d'événement d'effacement aussi bien pour les cas sud-coréens que français. Cependant, sans parler des analyses de sensibilité, afin de renforcer la robustesse des résultats des analyses coûts-bénéfices et des analyses décisionnelles, il serait judicieux de procéder au même analyse coûts-bénéfices et analyse décisionnelle sur les autres périodes d'une année qui ont des profils de charge assez différents, en même temps, en utilisant davantage les méthodes de Monte Carlo—cela ne changerait pas beaucoup les résultats, cependant. Ce type d'amélioration devrait être réalisé dans la prochaine opportunité de recherche.

Chapitre 5 - Conclusion

Nous avons commencé cette recherche en observant la réalité dans laquelle nous devons trouver des alternatives pour aborder les questions de fiabilité, flexibilité, efficacité, sécurité d'approvisionnement, émissions de gaz à l'effet de serre, changement climatique, intégration des énergies renouvelables dans les chapitres 1 et 2. Le raisonnement théorique a prouvé que l'effacement peut répondre efficacement à ces préoccupations. L'essentiel du raisonnement théorique est que l'effacement peut réduire les charges physiques, en particulier pendant les périodes de pointe, et qu'il a des impacts sur l'élasticité de la courbe de demande d'électricité. En fait, presque tous les avantages de l'effacement—améliorant la fiabilité, offrant la flexibilité, augmentant l'efficacité du système électrique, garantissant la sécurité de l'approvisionnement, diminuant le prix de l'électricité, réduisant des émissions de gaz à l'effet de serre, empêchant le changement climatique, aidant l'intégration des énergies renouvelables—dans la revue de la littérature du chapitre 1 découle de ces éléments essentiels d'effacement.

L'examen des contextes et de la revue de la littérature, y compris les définitions, les catégorisations, les avantages et les défis du chapitre 1, nous a fourni l'orientation de cette recherche que nous concentrons sur l'effacement, en particulier les programmes d'effacement orienté vers le marché, explicites et implicites pour des clients résidentiels. De plus, dans la revue de la littérature, nous avons constaté que les problèmes techniques ne sont plus un obstacle critique, mais nous avons besoin de plus d'études sur les méthodes précises d'estimation des courbes de référence, des analyses coûts-bénéfices appropriées, de meilleures conceptions du marché et des réglementations bien préparées pour l'effacement.

L'étude de cas des États-Unis au chapitre 2 méritait l'attention car, pour le moment, les États-Unis sont le premier pays en ce qui concerne les performances de la maîtrise de la demande d'électricité et d'effacement, et son étude de cas pourrait donner quelques idées pour les autres cas, comme la France et la Corée du Sud, chaque fois qu'ils sont confrontés à des problèmes ou souhaitent améliorer leurs conceptions de marché d'effacement. Étant donné que les principaux pays cibles de cette recherche sont la France et la Corée du Sud, le cas des États-Unis n'a pas été traité de manière approfondie, c'est donc l'une des limites de cette recherche. Dans les recherches suivantes, des études plus détaillées et spécifiques à l'État, telles que la Californie, le PJM, le Texas, New York, etc., sont nécessaires pour les mécanismes d'effacement aux États-Unis.

Bien que l'effacement ait une justification théorique claire et une variété d'avantages, les motivations spécifiques pour promouvoir des programmes d'effacement orienté vers le marché étaient différentes entre la France et la Corée du Sud. La France avait besoin de mesures pour faire baisser le prix sur le marché de gros ou diminuer les importations chères, et pour améliorer la fiabilité pendant les périodes de pointe. De plus, pour la transition énergétique, l'effacement est nécessaire pour mieux intégrer des énergies renouvelables croissants offrant plus de flexibilité. Pour la Corée du Sud, il est prévu que l'effacement sera utile pour garantir la fiabilité du système électrique et la sécurité de l'approvisionnement. Le gouvernement sud-coréen souhaitant supprimer progressivement les centrales nucléaires et réduire la part des centrales à base de combustibles fossiles, il perd plus d'options du côté de l'offre et doit mettre davantage l'accent sur la maîtrise de la demande d'électricité et l'effacement.

Les études de cas détaillées de la France et de la Corée du Sud et les comparaisons des marchés de l'électricité, les mécanismes d'effacement au chapitre 2 étaient impératifs pour comprendre les informations et spécifications fondamentales pour les analyses suivantes aux chapitres 3 et 4. Comme nous avons examiné les évolutions de le mécanisme français NEBEF et le DRTM sud-coréen, nous avons pu déterminer leurs schémas et caractéristiques de la performance. Grâce à cela, nous avons pu réduire la portée de la recherche et identifier la cible spécifique de la recherche en termes de marché, saison, date, heure et secteur.

Sur la base des informations fondamentales et des spécifications du mécanisme NEBEF français et du DRTM sud-coréen au chapitre 2, nous avons essayé de trouver des méthodes d'estimation des courbes de référence plus précises. Il était nécessaire pour les analyses coûts-bénéfices, analyses décisionnelles et analyses de sensibilité suivants. De plus, il était important de trouver de meilleures méthodes d'estimation des courbes

de référence car il est lié à la rémunération ultime, et donc aux motivations des clients résidentiels à participer aux programmes d'effacement.

À la suite de l'étude du chapitre 3, nous avons constaté que les méthodes d'estimation des courbes de référence du DRTM sud-coréen, en particulier les deux méthodes des courbes de référence de $CBL^{WMA} \cdot PAC$ et $CBL^{WMA} + SAA$, fonctionnent étonnamment très bien avec des taux d'erreur extrêmement faibles d'environ 0,5% tandis que toutes les méthodes d'estimation des courbes de référence de NEBEF ne fonctionnent pas très bien avec des taux d'erreur élevés d'environ 12%–25%. De plus, lorsque nous avons appliqué les deux méthodes d'estimation des courbes de référence de $CBL^{WMA} \cdot PAC$ et $CBL^{WMA} + SAA$ au profil de charge moyen des ménages français redimensionné pour établir les courbes de référence, il en est résulté une haute performance avec des taux d'erreur extrêmement bas inférieurs à 0,5% à nouveau.

De plus, les résultats des analyses complémentaires sur les différents profils de charge de différentes saisons sont en ligne avec les principaux résultats confirmant que les deux méthodes d'estimation des courbes de référence avec ajustement ($CBL^{WMA} \cdot PAC$ et $CBL^{WMA} + SAA$) sont les meilleurs même si les profils de charge sont plus stochastiques et volatile. Par conséquent, cette validation croisée entre différentes saisons dans un pays a ajouté la robustesse de la recherche. Avec les résultats, cette étude fournit à un pays, en particulier la France, une implication politique significative pour améliorer les méthodes d'estimation des courbes de référence de NEBEF et, finalement, la conception du marché d'effacement.

Comme le marché de l'effacement de la Corée du Sud, le mécanisme NEBEF est un mécanisme d'effacement orienté vers le marché assez récent, il évolue donc depuis les 'Règles NEBEF 1' en 2013. Même s'il semble que RTE ait testé de nombreuses méthodes d'estimation des courbes de référence depuis la phase expérimentale, par exemple, l'approche d'analyse des données du panel, il paraît que RTE n'a pas encore explicitement suggéré ou introduit les options alternatives comme le PAC et le SAA. Selon les résultats de cette recherche, les faibles performances et les taux d'erreur élevés des méthodes d'estimation des courbes de référence de NEBEF découlent du fait qu'elle ne repose que sur la moyenne et la médiane simple et n'utilise aucune option d'ajustement qui pourrait capturer les changements récents du profil de charge causés par quoi que ce soit un événement stochastique basé sur la température ou socio-économique.

Comme nous avons examiné les tendances en développement des mécanismes d'effacement sud-coréen et français en termes de volume et de fréquence, l'importance du mécanisme NEBEF sera plus importante avec des énergies renouvelables à apports variables, la préoccupation sur le changement climatique, la durabilité et la sécurité de l'approvisionnement d'électricité. Afin d'exploiter le mécanisme d'effacement à part entière en France, nous devons accorder plus d'attention à l'importance des méthodes précises d'estimation des courbes de référence qui sont les éléments fondamentaux pour encourager les participants potentiels. Comme nous l'avons observé, les méthodes d'estimation des courbes de référence actuellement utilisées sont susceptibles d'entraîner une sous-estimation des courbes de référence, ce qui se traduit par une sous-appréciation des efforts ou des réductions réels. Ces méthodes des courbes de référence inexactes pourraient saper le mécanisme français de NEBEF malgré son avantage tel que l'ouverture de haut niveau de tous les marchés pour les ressources côté de la demande.

En outre, il est prévu que les méthodes précises d'estimation des courbes de référence peuvent empêcher les participants de manipuler intentionnellement et malveillamment leur courbe de référence. C'est un point assez important du point de vue de l'opérateur du système d'effacement ou des opérateurs d'effacement. Si les méthodes d'estimation des courbes de référence sont très précises, alors les participants auront peu de place pour manipuler stratégiquement leur courbe de référence afin d'être rémunérés beaucoup plus qu'ils ne devraient l'être. Ce n'est qu'avec ces méthodes d'estimation des courbes de référence bien définies qui peuvent éviter la sous-estimation ou la surestimation en tant qu'erreur de mesure et les incitations stratégiques à compenser que l'optimalité des programmes d'effacement peut être garantie.

Compte tenu des implications politiques susmentionnées, cette étude offre une bonne occasion de mettre en lumière et de comparer les méthodes d'estimation des courbes de référence de la Corée du Sud et de la France. Il est rare de voir ce type d'analyse comparative entre pays se concentrant sur les méthodes d'estimation des courbes de référence dans la pratique. L'une des difficultés pour mener ce type de recherche est qu'il n'est

pas facile d'obtenir les profils de charge en temps réel d'un ménage individuel en raison des problèmes de confidentialité ou d'accès à l'information. L'approche dans laquelle nous avons utilisé le profil de charge redimensionné à partir des charges nationales agrégées a permis cette analyse. Les termes très clairs et distincts et les équations et explications simples mais détaillées seront utiles pour d'autres études sur les courbes de référence dans de nombreux pays qui développent activement des mécanismes d'effacement.

En plus de cela, les courbes de référence estimées ont joué un rôle de tremplin ou de fondation pour une analyse plus approfondie, comme l'analyse décisionnelle basée sur les analyses coûts-bénéfices et les analyses de sensibilité. Sans cette partie sur les courbes de référence, il sera presque impossible de poursuivre les recherches ou sera confronté à l'ambiguïté du mécanisme d'effacement. Uniquement sur la base des courbes de référence estimées avec précision, de la réduction de charge réelle, du niveau de rémunération optimal, de la désutilité marginale pour les participants avec l'effacement et le report de consommation, changement de comportement des participants (profil de consommation d'électricité avec d'effacement), de l'efficacité de la tarification selon l'heure d'utilisation, etc. peuvent être traités de manière appropriée.

Au chapitre 4, lors de la construction du modèle des analyses coûts-bénéfices, nous avons pu confirmer mathématiquement et systématiquement l'importance de méthodes d'estimation des courbes de référence précises. Elle a également été observée dans les analyses de sensibilité pour le cas français de NEBEF dans lequel la méthode d'estimation des courbes de référence a été remplacée par la méthode d'estimation des courbes de référence utilisée en Corée du Sud. Avec la méthode d'estimation des courbes de référence inexacte $CBL^{avg.10}$, les avantages nets étaient trop minimes, mais avec la méthode d'estimation CBL précise $CBL^{WMA} + SAA$ nous avons observé le décalage horizontal significatif et positif avec des avantages nets accrus. Par conséquent, la méthode d'estimation des courbes de référence peut jouer un rôle important dans la prise de décision de la participation d'effacement, et le fonctionnement transparent et durable.

De plus, nous avons pu comprendre l'importance des degrés d'inconvénients supplémentaires (coefficient β) à la fois pour l'effacement et le report de consommation dans les analyses coûts-bénéfices et les analyses de sensibilité. Dans l'analyse coûts-bénéfices pour le cas sud-coréen, le client résidentiel a déplacé la réduction de charge requise juste avant et après les plages horaires d'événement d'effacement—le profil similaire a également été confirmé pour le cas français de transfert de charge NEBEF dans lequel des réductions de charge ont été déplacé juste après l'événement d'effacement. Elle est le résultat de l'optimisation des coûts (programmation linéaire) en tenant compte des coûts d'inconvénients supplémentaires. En outre, dans les analyses de sensibilité pour le cas sud-coréen et français dans lesquels les impacts de la variation de la valeur β ont été examinés, car la valeur β augmente, les coûts augmentent et, par conséquent, un client résidentiel finit par décider de ne pas participer au programme d'effacement—ou d'aller beaucoup plus loin s'il n'était pas dans la zone de participation d'effacement au tout début. Ce résultat nous donne une implication politique significative que lorsqu'un opérateur de système d'effacement conçoit le marché d'effacement, il doit examiner attentivement les coûts ou les perceptions d'inconvénients supplémentaires objectifs ou subjectifs d'un client pour l'effacement et le report de consommation.

On a également pu observer qu'il y avait un très léger décalage vertical avec le changement du régime tarifaire. Cela signifie que s'il y a une très petite différence entre les prix des périodes de pointe et des périodes creuses, il n'y aurait pas de motivations importantes pour un client résidentiel à participer au programme d'effacement. Par conséquent, si un opérateur de système d'effacement souhaite promouvoir un programme d'effacement avec un schéma tarifaire implicite de ToU, il devrait y avoir une forte différenciation des prix entre la période de pointe et la période creuse.

Tout comme l'importance du coefficient β , l'importance de la forme fonctionnelle de $Coef^{INC}$ a été confirmée. Que la forme fonctionnelle d'un participant de $Coef^{INC}$ soit linéaire ou exponentielle a des impacts sur les coûts et, à son tour, cela pourrait changer la décision à quelle plage horaire le participant reportera les réductions de charge pour minimiser les coûts d'inconvénients supplémentaires.

Nous avons également été témoins des impacts très importants du SMP avec les SMP les plus élevés et les plus bas. C'est très naturel et conforme à l'objectif intrinsèque d'effacement—lorsqu'il y a une demande de pointe, le SMP est élevé et cela donne aux clients une plus grande motivation pour participer au programme

d'effacement. En conséquence, il peut réduire la demande de pointe et atteindre la fiabilité avec cette flexibilité. C'est un point très important car l'avantage pour les participants est la fonction du SMP, même s'il s'agit du régime tarifaire uniforme, la participation d'effacement joue un rôle de lien entre le marché de gros et le marché de détail. Le régime tarifaire uniforme ne peut pas envoyer le véritable signal sur les coûts marginaux de la fourniture d'électricité, cependant, les participants d'effacement peuvent recevoir les informations sur les prix lorsqu'ils participent au mécanisme d'effacement. Par conséquent, l'effacement peut corriger le signal du marché déformé et augmenter l'efficacité du système électrique.

De plus, les seuils SMP calculés ont clarifié davantage la frontière entre participation et non-participation pour un client résidentiel avec une valeur β spécifique. Ces seuils SMP pourraient nous fournir, en particulier pour les opérateurs d'effacement et les opérateurs de systèmes d'effacement, des informations précieuses sur l'attente de la participation pour une tranche de temps spécifique avec un SMP spécifique. Les informations détaillées sur les seuils SMP réduiront l'incertitude autour de l'avantage net et, par conséquent, augmenteront les motivations à participer.

En plus du SMP lui-même, lorsque nous comparons les deux différents mécanismes d'effacement de la Corée du Sud et de la France, l'importance du niveau approprié de rémunération a été soulignée. Contrairement au cas sud-coréen, dans le mécanisme français de NEBEF, une partie, c'est-à-dire 'Versement' v du SMP doit être transférée au fournisseur d'électricité, donc la rémunération finale pour les clients résidentiels sont trop négligeables pour les encourager à participer au programme d'effacement. Quel est le niveau idéal pour la rémunération d'effacement est une question qui nécessite une autre recherche approfondie, et il semble que *a priori* le cas français est plus proche du niveau de rémunération d'effacement théoriquement idéal, mais le cas sud-coréen est plus encourageant pour les participants potentiels à l'effacement. L'opérateur du système d'effacement français RTE pourrait donc prendre en compte le niveau de rémunération d'effacement pour le programme d'effacement durable.

Même si l'analyse coûts-bénéfices est absolument impérative pour un programme d'effacement, et que le modèle d'analyse coûts-bénéfices construit dans cette étude est assez simple, il n'existait pas jusqu'à présent ce type de modèle fondamental et de recherche. Faire bon usage du modèle mathématique explicite et simple de l'algèbre linéaire rend le mécanisme d'effacement ambigu simple et clair. Avec ce modèle mathématique simple, il a été possible de comprendre clairement les interactions entre une série de composants d'un mécanisme d'effacement, tels que des courbes de référence, capacité réductible maximale, réduction de charge requise, réduction de charge effectivement remplie, SMP, schéma tarifaire, l'effacement et le report de consommation, des coûts d'inconvénients supplémentaires, etc.

L'art de ce modèle simple est que le processus d'analyse est continu depuis le tout début de l'estimation des courbes de référence, des analyses coûts-bénéfices, des analyses décisionnelles, puis enfin jusqu'à des analyses de sensibilité avec des concepts et des éléments assez cohérents. Par conséquent, l'ensemble de ce modèle fournit un package pour l'analyse d'un mécanisme d'effacement. Le modèle utilisé dans cette étude est également assez générique, ce qui signifie qu'il peut être appliqué à d'autres programmes d'effacement industriels ou commerciaux, ou dans d'autres pays où les gestionnaires de réseau envisagent d'introduire des programmes d'effacement.

En ce qui concerne les limites de cette étude, il y a plusieurs limites à signaler pour les recherches suivantes, bien que nous en ayons déjà mentionné quelques-unes. Dans le chapitre 3, nous nous sommes appuyés sur les profils de charge redimensionnés afin de trouver des méthodes d'estimation des courbes de référence plus précises et d'établir les courbes de référence en conséquence. Redimensionner les profils de charge agrégés nationaux à un profil de charge moyen des ménages, c'est une méthode que nous avons trouvée afin de surmonter le problème des données non disponibles sur le niveau de la clientèle résidentielle individuelle. Par conséquent, c'est l'une des limites de cette recherche, et dans l'étude suivante, l'analyse empirique avec les données réelles pour chaque pays, la France et la Corée du Sud, devrait être effectuée afin de vérifier les méthodologies et les modèles utilisés dans cette recherche.

Dans cette recherche, puisque nous nous sommes concentrés sur la demande de pointe et le potentiel d'effacement pour réduire la demande de pointe, nous avons supposé que les périodes d'événement

d'effacement sont données. Mais ce n'est pas toujours le cas. Dans le cadre du programme d'effacement économique en Corée et en France, les opérateurs d'effacement, au nom des participants, peuvent soumissionner des ressources côté de la demande à tout moment si cela est rentable pour eux et leurs clients. Leur prise de décision sur le créneau horaire auquel ils soumissionneront peut également être traitée en optimisation des coûts (programmation linéaire) en interne. Pour le programme *Peak Reduction DR* en Corée du Sud, le modèle d'analyse coûts-bénéfices utilisé dans cette étude est suffisant, mais pour le programme *Economic DR* en Corée du Sud et en France, il a besoin de ce type d'extension du modèle d'analyse coûts-bénéfices.

De la même manière, dans ces analyses coûts-bénéfices, j'ai choisi les jours de pointe pour le jour de l'événement d'effacement à la fois pour les cas sud-coréen et français. Cependant, sans parler des analyses de sensibilité, afin de renforcer la robustesse des résultats de l'analyse coûts-bénéfices et de l'analyse décisionnelle, ce serait une bonne idée de mener la même analyse coûts-bénéfices et analyse décisionnelle sur les autres périodes d'une année qui ont des profils de charge assez différents, en même temps, en utilisant davantage les méthodes de simulation de Monte Carlo—cela ne changerait pas beaucoup les résultats, cependant. Ce type d'amélioration devrait être réalisé dans la prochaine opportunité de recherche.

Même si nous avons mis en évidence la différence des niveaux de rémunération entre le marché de l'effacement de la Corée du Sud et NEBEF et confirmé l'importance du niveau de rémunération pour promouvoir la participation, une étude plus détaillée devrait être effectuée à ce sujet et des concepts associés comme *NBT (Net Benefit Test)* et *NBTP (Net Benefit Test Price ou Net Benefit Threshold Price)* que j'ai simplement mentionné au chapitre 2.

Pendant que je menais cette recherche, les deux programmes d'effacement en Corée du Sud et en France étaient des mécanismes très nouveaux-nés, et il n'y avait pas beaucoup de données disponibles. Cependant, avec le temps, de plus en plus d'ensembles de données sont disponibles pour le public et les chercheurs, tels que les informations sur les offres de ressources du côté de la demande sur les marchés d'effacement. Par conséquent, il sera nécessaire d'analyser plus en détail les ensembles de données des enchères.

De plus, nous ne pouvions pas traiter d'autres questions pertinentes pour l'effacement, telles que le système de stockage d'énergie, les véhicules électriques, les ressources du côté de l'offre, etc., car cette étude ne portait que sur l'effacement. Les interactions et les relations entre l'effacement et ces autres ressources, par exemple, une analyse sur la façon dont l'effacement peut être utile pour une meilleure intégration des énergies renouvelables à apports variables au réseau électrique, seraient de bons sujets pour les recherches suivantes.

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RÉSUMÉ

À cause de la préoccupation mondiale sur les émissions de CO₂, le changement climatique, et la transition énergétique, nous faisons plus d'attention à la maîtrise de la demande d'électricité. En particulier, avec l'effacement de consommation électrique, nous pouvons profiter de plusieurs avantages, comme l'augmentation de l'efficacité de l'ensemble du marché de l'électricité, la sécurité d'approvisionnement d'électricité renforcée, et l'investissement plus efficace et souhaitable ainsi que l'avantage de l'environnement et le soutien aux énergies renouvelables. En Europe, la France a démarré le mécanisme de NEBEF à la fin de 2013, et la Corée du Sud a lancé le programme de l'effacement de consommation électrique basé sur le marché fin 2014. Parmi un certain nombre de questions et d'hypothèses que nous devons prendre en compte en termes de l'effacement, l'estimation de la courbe de référence est l'un des éléments les plus importants et les plus fondamentaux. Dans cette recherche, sur la base du profil de consommation redimensionné pour un ménage moyen, plusieurs méthodes d'estimation de la courbe de référence sont établies et examinées à la fois pour les mécanismes de l'effacement français et coréen. Cette investigation sur les méthodes de l'estimation pourrait contribuer à la recherche d'une méthode d'estimation meilleure et plus précise qui augmentera les motivations pour les participants. Avec les courbes de référence estimées, les analyses coûts-bénéfices ont été réalisées, elles-mêmes utilisées dans l'analyse décisionnelle pour les participants. Pour réaliser les analyses coûts-bénéfices, un modèle mathématique simple utilisant l'algèbre linéaire est créé et modifié afin de bien représenter les paramètres de chaque mécanisme de l'effacement. Ce modèle nous permet une compréhension intuitive et claire des mécanismes. Ce modèle générique peut être utilisé pour différents pays et secteurs, résidentiel, commercial et industriel, avec quelques modifications de modèle. La simulation de Monte Carlo est utilisée afin de refléter la nature stochastique de la réalité, et l'optimisation est également utilisée pour représenter et comprendre la rationalité des participants, et pour fournir des explications microéconomiques sur les comportements des participants. Afin de dégager des implications significatives pour une meilleure architecture du marché de l'effacement, plusieurs analyses de sensibilité sont effectuées sur les éléments clés du modèle pour les mécanismes.

MOTS CLÉS

l'Effacement de Consommation Électrique, la Courbe de Référence, l'Analyse Coûts-Bénéfices, la Simulation Monte Carlo, l'Optimisation, l'Analyse de Sensibilité, NEBEF, l'Opérateur d'Effacement

ABSTRACT

Worldwide concern on CO₂ emissions, climate change, and the energy transition made us pay more attention to Demand-side Management (DSM). In particular, with Demand Response (DR), we could expect several benefits, such as increased efficiency of the entire electricity market, enhanced security of electricity supply by reducing peak demand, and more efficient and desirable investment as well as the environmental advantage and the support for renewable energy sources. In Europe, France launched the NEBEF mechanism at the end of 2013, and South Korea inaugurated the market-based DR programs at the end of 2014. Among a number of economic issues and assumptions that we need to take into consideration for DR, Customer Baseline Load (CBL) estimation is one of the most important and fundamental elements. In this research, based on the re-scaled load profile for an average household, several CBL estimation methods are established and examined thoroughly both for Korean and French DR mechanisms. This investigation on CBL estimation methods could contribute to searching for a better and accurate CBL estimation method that will increase the motivations for DR participants. With those estimated CBLs, the Cost-Benefit Analyses (CBAs) are conducted which, in turn, are utilized in the Decision-making Analysis for DR participants. For the CBAs, a simple mathematical model using linear algebra is set up and modified in order to well represent for each DR mechanism's parameters. With this model, it is expected to provide an intuitive and clear understanding of DR mechanisms. This generic DR model can be used for different countries and sectors (e.g. residential, commercial, and industrial) with a few model modifications. The Monte Carlo simulation is used to reflect the stochastic nature of the reality, and the optimization is also used to represent and understand the rationality of the DR participants, and to provide microeconomic explanations on DR participants' behaviors. In order to draw some meaningful implications for a better DR market design, several Sensitivity Analyses (SAs) are conducted on the key elements of the model for DR mechanisms.

KEYWORDS

Demand Response (DR), Customer Baseline Load (CBL), Cost-Benefit Analysis (CBA), Monte Carlo Simulation, Optimization, Sensitivity Analysis (SA), NEBEF, Load Aggregator (LA)