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MODELLING PARTICIPATION IN RESIDENTIAL *DEMAND RESPONSE* MECHANISMS IN SOUTH KOREA AND FRANCE: THE IMPACTS OF INCONVENIENCE, CUSTOMER BASELINE ESTIMATION AND MARGINAL PRICING

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MODELLING PARTICIPATION IN RESIDENTIAL DEMAND RESPONSE MECHANISMS IN SOUTH KOREA AND FRANCE: THE IMPACTS OF INCONVENIENCE, CUSTOMER BASELINE ESTIMATION AND MARGINAL PRICING

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Abstract

In this study, the Cost-Benefit Analyses (CBAs) and the Decision-making Analyses are conducted in order to provide a framework that allows the Demand Response (DR) system operators in South Korea and France to assess the expected level of residential customers' participation according to the loss of consumer surplus based on different Customer Baseline Loads (CBLs). With the economic assumption of rationality, it is found that DR participants shift their loads to just before or after the DR event period as a result of the optimization of the costs considering their stochastic conditions. The degree of the additional inconvenience and its functional form of the DR program participants have significant impacts on their decision-making of the DR participation. The importance of the accurate CBL estimation methods is mathematically and systematically reconfirmed with the CBA model and the Sensitivity Analysis (SA). In terms of the marginal pricing, there should be a stark pricing differentiation between the peak and off-peak periods to provide more incentives. As a higher SMP (System Marginal Price) provides larger remuneration for participants, DR can make a bridge between the wholesale market and the consumers of electricity by sending a wholesale market price signal. With these key results, it is expected that this study can provide the DR system operators in two countries with meaningful policy implications for a better and well-functioning DR market design.

Keywords: Demand Response (DR), Cost-Benefit Analysis (CBA), Decision-making Analysis, Optimization (Linear Programming), Monte Carlo Simulation, Sensitivity Analysis (SA).

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I. INTRODUCTION

The most significant benefit of Demand Response (DR), which is one sub-category of Demand-side Management (DSM), is the reduction of loads during the peak period. Once DR could play a role as resources of flexibility, there needs less capacity on standby and less investment in the expensive marginal power plants that are usually gas-fueled. As a consequence, we can avoid the costs for transmission & distribution infrastructure and the environment.

In this respect, DR is a particularly promising option in countries with strong demand-supply imbalances and low social acceptance against additional power plant installations. In South Korea, due to the lack of electricity supply for the high electricity demand, there was an unprecedented rotating blackout on September 15, 2011. Moreover, the president Moon set out the new energy policy in which the phase-out of nuclear power plants and the shutdown of at least 10 aged coal-fired power plants are pledged. In this context, South Korea's Demand Response Mechanism (DRM), called Demand Resource Trading Market (DRTM), will be getting more important in South Korea.

Likewise, French people have seen the historic peak demand of 102.1 GW on February 8, 2012. Moreover, France imports the expensive electricity from its neighbors to meet the peak-load for electric heating during the extremely cold winters. Therefore, it can be said that the motivation of introducing the DRM, called La Notification d'Échange de Blocs d'Effacement (NEBEF), in France is affordability and sustainability because thanks to the DRM it can avoid extremely high peak demands and reduce the imports during winter, and as a result, it can decrease the price on the wholesale market. In addition, we cannot neglect the benefit of DR as a flexibility resource and back-up for the high penetration or integration of Renewable Energy Sources (RESs) in France.

In the past, the huge costs and investments for the Advanced Metering Infrastructure (AMI) were the main obstacles for DR programs, but nowadays one of the great barriers to the active implementations of DR is the uncertainty around the true costs and benefits of the programs [27, p. 688]. Therefore, to overcome the obstacle, the precise and comprehensive Cost-Benefit Analysis (CBA) is required [5, p. 312; 30, p. 4425; 6, p. 1]. Since the objective of a CBA is to evaluate whether or not there are net economic benefits associated with introducing a DRM under current circumstances [16, p. 2], it is quite useful for decision-makers to decide whether or not to introduce a DR program, especially, when there are various possible designs around the DR program. The CBA approach can provides us with transparent and objective assesssment of different options, such as Time-of-Use (ToU), Critical Peak-Pricing (CPP), and Real-time Pricing (RTP), and the information on the optimal timing and scope of DR programs.

So far, 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 Energy Efficiency (EE) and DR; secondly, it was the Cost-Effectiveness Analysis (CEA) on the Smart Grid (SG) which, of course, includes DR. The 'five cost-effectiveness tests', so-called

'California Tests'[1], in the *California Standard Practice Manual* [7, 8, 9] and the researches conducted by Federal Energy Regulatory Commission (FERC) [31] became the industrial standard. In the beginning, it was developed for EE, and then the framework was applied to DR programs later. The U.S. by Electric Power Research Institute (EPRI) and EU[2] by Joint Research Centre (JRC) have prepared well-elaborated frameworks for the CEA on the SG. Electric Power Research Institute (EPRI) [12, 13, 14] 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 [18, 19, 20, 21].

Even though those previous researches are very valuable to refer, because their foci were on the very comprehensive CEA on the SG and installations of the AMIs targeting very large industrial and commercial clients, there is not enough studies focusing on the specific residential and explicit market-based DR programs. As a result, it lacks the understanding on the residential DR program, the expected level of residential clients' participation, and key variables impacting on their participation. In this regard, the objective of this research is to provide a framework that allows the DR system operators in South Korea and France to assess the expected level of residential customers' participation according to the loss of consumer surplus based on different customer baselines. 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 and to which time slot does the client shift the electricity consumptions in order to minimize the costs. In addition, Sensitivity Analysis (SA) has been conducted to take into consideration all the possible variations of the key variables, such as the degree of the additional inconvenience due to the load shedding or shifting and its functional form, different CBL estimation methods, changes of the marginal pricing, and System Marginal Price (SMP).

This article is structured as follows. In Section 2 the model will be constructed for the CBA of the South Korean and French DRMs. Subsequently, in Section 3 the model for the Decision-making Analysis will be established, and the results will be presented. In Section 4 SAs will be conducted in order to figure out the impacts of the changes in the key parameters of the CBA model, and the results will be discussed. Finally, in Section 5 the policy implications of the results of the CBA, Decision-making Analysis, and SA will be drawn, and we will conclude the article.

[1] In the 'California Tests', there are 'Participant Cost Test', 'Rate Impact Measure Test', 'Program Administrator Cost Test', 'Total Resource Cost Test', and 'Societal Cost Test'.

[2] In the Annex I of the Directive on Internal Markets (DIM) [10, 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.

II. CBAS FOR SOUTH KOREAN AND FRENCH DR MECHANISMS

2.1. CBA Model for the Korean Demand Resource Trading Market (DRTM)

We proceed to the CBA for the residential participants of the DR program based on the experimentally established Customer Baseline Load (CBL) with the Weighted Moving Average (WMA) + Symmetric Additive Adjustment (SAA) option that is one of the best CBL estimation methods used in South Korea.[3] First of all, we set up a 'reference scenario' with the country-specific circumstances and assumptions on the required load reduction, different remuneration schemes, the proportion of the remuneration to participants, the cost function, consumers' behaviors, stochastic constraints of a participant, and so forth, and then several alternative scenarios in which we set up different assumptions in terms of those factors will be dealt with in Section 4.

In terms of the required load reduction, we assume 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 [24]. Looking at the cumulative density distribution of all the hourly loads for the 20 maximum reference days, the fifth percentile is 482 (W).

Next, in order to calculate the maximum profit, the **objective function** of the **optimization (linear programming)** is to maximize the net benefits of a residential participant, that is, to minimize the net costs for the electricity consumption (Eq. B.1 in Appendix).

The constraints (Eq. B.2 in Appendix) mean that each element of the decision variable **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 **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 t. We 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, we 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, the upper bound (maximum value) for the the variable **Cap** has been synchronized with the Required Flexibility Level (RFL). From the DR system operator's perspective, if the

[3] In terms of the CBL estimation methods and the experimentally constructed CBLs that are used in this article both for the South Korean and French cases, please refer to the following working paper: LEE [25].

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 RFL, and vice versa.

In addition, it is worthwhile highlighting that the required load reduction $\mathbf{r}$ and actualized load reduction $\mathbf{r}'$ are different (Eq. B.8 in Appendix). For the required load reduction $\mathbf{r}$, the residential participant will reduce this amount from the original load $(\ell_{17},\ \ell_{18})$, and then, the actualized load reduction $\mathbf{r}'$ is calculated as the difference between CBL and actualized loads ($\boldsymbol{\ell}''$).

Here, we can mathematically and systematically 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. Focusing on the hourly SMPs for $t = 17h$ and $t = 18h$ on Friday, August 12, 2016 in South Korea, it was 80.05 and 78.69 ₩/kWh, respectively. If there is no DR event and no required reduction, the remuneration will be zero, '0' because $r_t = 0$, where, $t \in T = \{1, 2, \ldots, 24\}$. In terms of the variable ϕ in the objective function (Eq. B.1 and B.9 in Appendix), let us assume '1' as a default value for ϕ in the 'reference scenario' which means that all the remuneration will be paid for the residential participant and there is no gain divided for the Load Aggregator (LA).

When it comes to the first part of the cost function (Eq. B.10 in Appendix), 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[4], the retail price varies depending on time, day, and season (Eq. B.11 in Appendix). For the uniform price scheme, we will take the the unit retail price for residential usage in 2015, that is, 124 ₩/kWh.

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, $\mathbf{p}' \times \boldsymbol{\ell}$. The total tariff accounts for all 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.

On top of the total tariff for the electricity consumption, we need to consider the additional inconvenience costs (Eq. B.14 in Appendix) 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

[4] 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, the ToU tariff scheme for industrial and commercial clients was utilized as a reference. According to the '2nd Master Plan for Smart Grids (2018–2022)' announced in August 2018 [26], 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 equipped with the AMIs until 2020.

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 and daily 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, which 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.[5] 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 is no additional cost due to inconvenience on top of the total tariff for the actual consumption. In the second case, the costs of inconvenience increases as the time distance (interval) increases.

For example, the unit value for the shifted load can be proportional to the time distance (Eq. B.12 in Appendix) 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 terms of the increase rate of the unit value of the shifted load, it can be a constant (let's say $\beta = 0.5$), which means this inconvenience cost function is a linear model, and also it can be quadratic or exponential in terms of the time distance, $\mathbf{d}$.

2.2. CBA Model for 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') in the French NEBEF mechanism. It is the

[5] 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 $t = 19h$ 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.

difference between South Korea and France in that in the 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 DRTM of South Korea categorizes two types of trade: 'economic' DR resources and 'reliability' DR resources. However, in the NEBEF mechanism, Réseau de transport d'électricité (RTE) makes two types of DR distinct explicitly. Therefore, in this section, we 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 an LA) to reduce the DR participants' loads during the DR event time in the 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. As a consequence, in this French case, the terms 'Required Reduction Level' and 'Required Load Reduction' have changed into 'Target Reduction Level' and 'Target Load Reudction' because LAs can choose and then declare it to RTE themselves. However, because the amount of load shedding or load shifting is up to LAs, it is very arbitrary. For the systematic analysis, we 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.

In the case of NEBEF's load shedding, the model remains almost the same with the South Korean DRM and its CBA. However, some specific elements need modifications to represent the characteristics of the NEBEF mechanism and the distinction between load shedding and load shifting in the NEBEF mechanism. For instance, in the **objective function** of NEBEF's load shedding (Eq. B.17 in Appendix), we can notice that there is no **x** decision variable, which represents the weights or coefficients of the load shifting, in the costs part. Therefore, we can regard this model as the previous model for South Korea with zero **x** decision variable. 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 $t = 38$).

In terms of the benefit function, there is a small difference from the South Korean case. For the actualized load reduction the LA will be remunerated at the level of SMP in the wholesale market [European Power Exchange (EPEX)], and the LA should transfer the fixed amount (**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'.[6] 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'), day (weekdays and weekends), the quarter in a year, and the tariff option.

[6] RTE [28, pp. 91–103], 9. Versement dû aux fournisseurs des sites effacés; RTE [29].

At this stage the 'Versement' (transfer) for 'les Sites de Soutirage Profilés en option tarifaire Base (1)', which is 43.58 €/MWh[7], will be considered 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'). After this transfer to the electricity supplier, the remaining remuneration will be divided between the LA and the residential participant.[8] 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 73.07 €/MWh. If there is no DR event and no target reduction, the net benefit will be zero, '0' because $r_t = 0$, where, $t \in T = \{1, 2, \ldots, 48\}$.

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. B.10 in Appendix) 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' [31, pp. v–vi]. This additional inconvenience is that due to load shedding we cannot consume the electricity, and that we cannot fulfill associated activities with this electricity consumption, so it causes some loss of the welfare from the consumer's perspective—i.e., loss of the marginal utility. If it were the industrial sector, theses 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.

In terms of the retail price of the uniform tariff scheme, the average retail price for electricity in 2016, that is, 164.8 €/MWh, is used because the focus is on an average household using the rescaled load profile [17, p. IV.8]. For the retail price of the ToU tariff scheme, at this stage, the tariff scheme of 'Option Heures Creuses' of EDF is used in which the price is 16.00 cts €/KWh for peak time ('Heures Pleines', between 8 a.m. and 8 p.m.) and 11.14 cts €/KWh for off-peak time ('Heures Creuses', between 8 p.m. and 8 a.m.).[9]

Instead of the vector of time distance **d** (Eq. B.12 in Appendix), here it will be generalized to represent the coefficient of inconvenience due to load shedding (also, it can be applied to load shifting later). The coefficient vector $\mathbf{coef}^{\mathbf{INC}}$ can vary depending on each residential participant's different condition, perception of inconvenience for each time slot. Here, let us set this value as '1' for all the time slots, which means for this residential participants the degrees of inconvenience due to the load shedding is all the same across the time slots. With this generalized inconvenience vector $\mathbf{coef}^{\mathbf{INC}}$, the formula for **INC** for load shedding is also modified a little bit.

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

[7] 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: La Commission de Régulation de l'Energie (CRE) [23].

[8] Therefore, the accessible remuneration level (net remuneration) for industrial participants is given as the following [1, pp. 29–30]: (Prix de marché [€/MWh] − Montant du versement [€/MWh] − Coût d'activation) × Volumes effacés [MWh]

[9] Applicable from August, 2015 to July, 2016 [11].

value of β representing different participants' perceptions on the value of WTA for the inconvenience to reduce their as usual loads.

In the case of NEBEF load shifting, the model remains almost the same with the NEBEF load shedding case. However, some specific elements need modifications to represent the characteristics of the NEBEF load shifting. In the following objective function (Eq. B.18 in Appendix), we can notice that there is $\mathbf{x}$ variable like Equation B.1 in Appendix for the South Korean case, which represents the weights or coefficients of the load shifting, in the costs 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 the values of $\mathbf{x}$ for time slots from $t = 1$ to $t = 37$ and $t = 38$ are zero (0), and all the values of $\mathbf{x}$ for time slots from $t = 39$ to $t = 48$ are greater than or equal to zero (0). 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 $t = 18$.

The target load reductions are the same with the load shedding case of the NEBEF mechanisms 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 decision variable $\mathbf{x}$. Moreover, the following $\boldsymbol{\ell}'$ is used for $\boldsymbol{\ell}''$, and in turn, $\mathbf{r}'$.

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

III. DECISION-MAKING ANALYSIS AND RESULTS

If the total profit of a residential client with participation in a DR program (Π_1) is greater than the total profit of him/her without participation in a DR program (Π_0), the residential client will participate in the DR program (Eq. B.19 in Appendix). It is the basic idea of decision-making based on the CBA. Actually, it means 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 (Eq. B.20 in Appendix). If the slope (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. We will do the Decision-making Analysis based on CBA in the 'reference scenario' under the following assumptions for South Korean DRTM and French NEBEF, respectively (Box 1):

Box 1: Assumptions of 'Reference Scenario' [South Korean DRTM (left) & French NEBEF (right)]

1. Required flexibility level: • 40% $\Rightarrow \mathbf{r_{40}}$,	1. Target flexibility level: • 40% $\Rightarrow \mathbf{r_{40}}$,
2. CBL estimation method: • $\text{CBL}^{\text{WMA}} + \text{SAA}$,	2. CBL estimation method: • $\text{CBL}^{\text{avg.10}}$,
3. Tariff scheme: • uniform tariff scheme, • 0.124 ₩/Wh, $\mathbf{p^u} = c = 0.124$, $t \in T = \{1, 2, \ldots, 24\}$,	3. Tariff scheme: • uniform tariff scheme, • 0.01648 cts €/Wh, $\mathbf{p^u} = c = 0.01648$, $t \in T = \{1, 2, \ldots, 48\}$,
4. Inconvenience costs: • $\beta = 0.5$, • linear function of $\mathbf{Coef}^{\text{INC}}(\mathbf{d})$,	4. Inconvenience costs: • $\beta = 0.5$, • linear function of $\mathbf{Coef}^{\text{INC}}$,
5. SMP: • SMPs of DR event day (2016-08-12).	5. SMP: • SMPs of DR event day (2016-01-18).

As a result of the Decision-making Analysis based on the CBA, the following Figure 1 represents the actualized loads with the solution for the optimization (linear programming)[10] and the loads without DR participation, and the differential Cost-Benefit ratio is $\theta = \frac{\Delta C}{\Delta B} = 0.810$ (Fig. 2). 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 status quo in terms of the profit optimization (cost minimization). Figure 2 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.[11]

[10] This linear programming was solved by relying on the R Package called '`lpSolve`' [4] which stands for 'linear programming solve'. In terms of the stochastic feature of this modeling, which is the variable '**Cap**' in the above constraint equations and inequalities, the command '`set.seed()`' was used for the reproducible research result and reconfirm the numerical result again.

[11] For this 'Cost-Benefit Plane', the R Package '`BCEA`' created by Baio et al. [2, 3] was utilized with some modifications—`BCEA` stands for 'Bayesian Cost Effectiveness Analysis'.

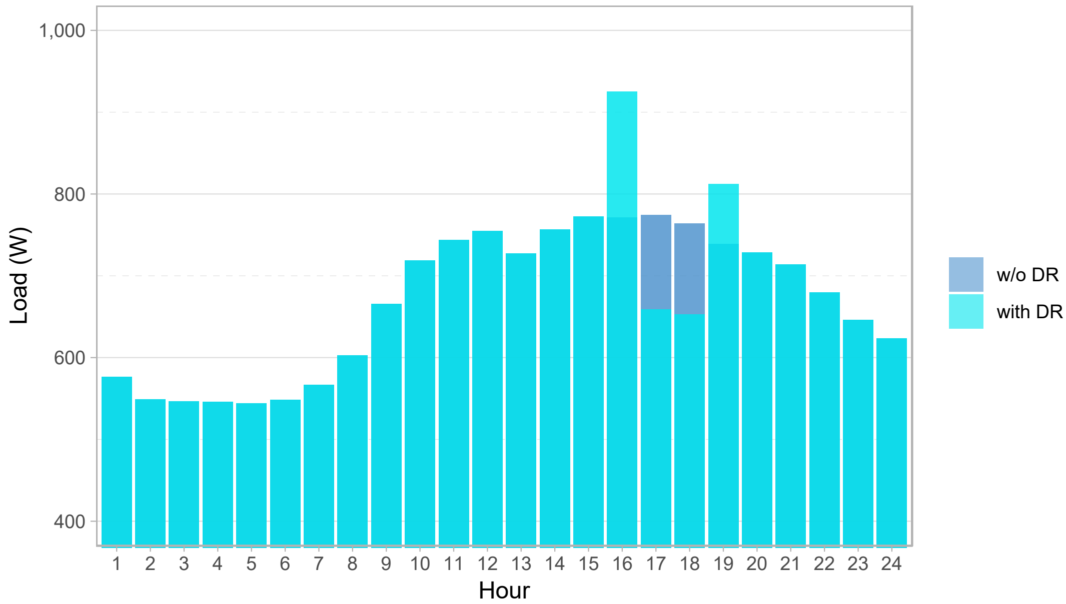


Figure 1: Actualized Load Comparison between without DR and with DR Participation (Wh, South Korean DRTM)

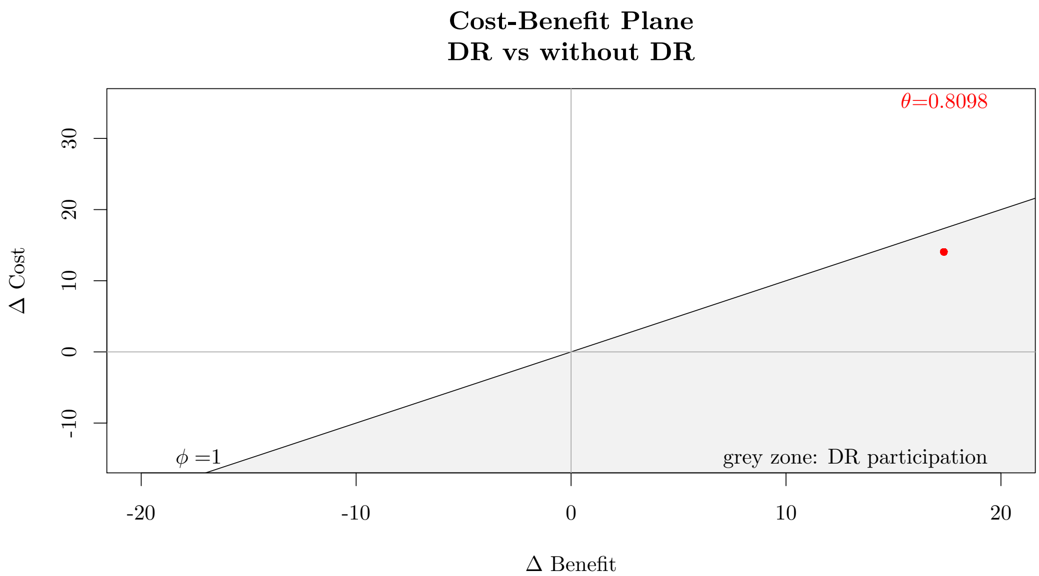


Figure 2: Cost-Benefit plane: DR vs. without DR (South Korean DRTM)

As a result of the Decision-making Analysis based on the CBA for the French NEBEF load shedding case, the ratio of cost-benefit differential (θ) is $\theta = \frac{\Delta C}{\Delta B} = -190.739$, and the the point is in the grey DR participation zone like the South Korean case above. For NEBEF load shifting, the following Figure 3 shows the resulting actualized loads with DR participation considering only load shifting, not load shedding—loads shifted to the time slots $t = 39$ and $t = 40$, which are just after the DR event period, as a result of the optimization of the costs considering stochastic conditions, and the ratio of cost-benefit differential (θ) is $\theta = \frac{\Delta C}{\Delta B} = 576.9307$ (Fig. 4). As can be seen in the Figure 4, 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.

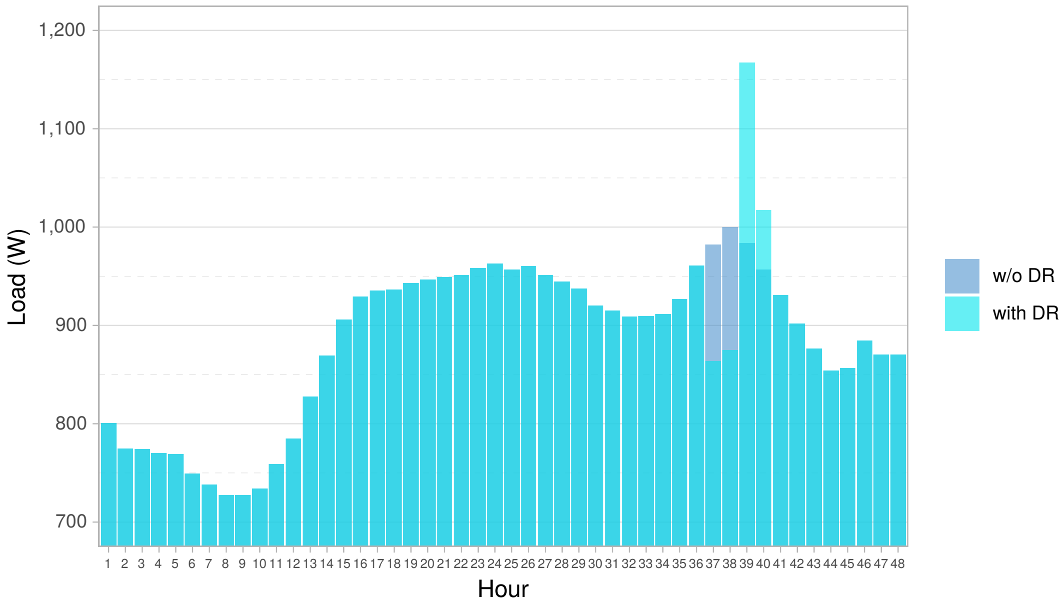


Figure 3: Actualized Load Comparison between without DR and with DR Participation in NEBEF Mechanism (W, Load Shifting, French NEBEF)

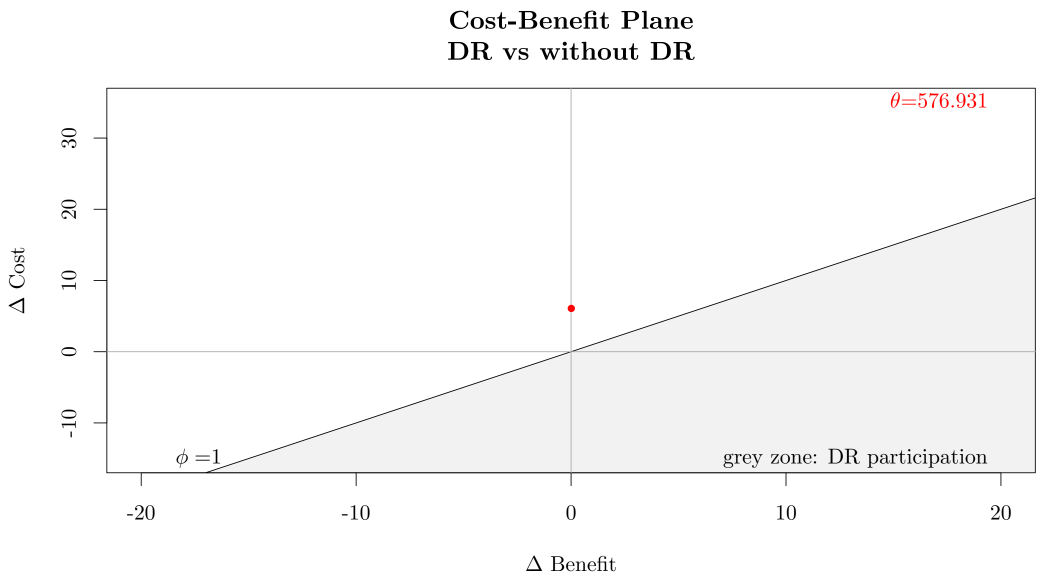


Figure 4: Cost-Benefit plane: DR vs. without DR (Load Shifting, French NEBEF)

IV. SENSITIVITY ANALYSIS AND DISCUSSION

Following the CBA and Decision-making Analysis on the residential sector in South Korea, under the 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, the 1,000-time simulations with 1,000 different vectors of **Cap** have been conducted, and the mean value of θ was obtained. The value of θ was 0.810 with one specific **Cap** vector, but as the number of simulations increases, it is approaching the value of 0.886. Therefore, under these conditions, where the β value is 0.5, the uniform tariff scheme, and 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—while the maximum value for ϕ is 1. 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. All the following points are the resulting mean points of the 1,000-time simulations with 1,000 different vectors of **Cap**.

Figure 5 shows the SA in which the value of θ is verified according to the different β values, from 0.5 to 1.5 increasing by 0.1 (Box 2). 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 values 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 2: Assumption Changes from 'Reference Scenario': Inconvenience Costs (South Korean DTRM)

4. Inconvenience costs: • $\beta = 0.5$	⇒	4. Inconvenience costs: • $\beta = 0.5$–1.5, by 0.1

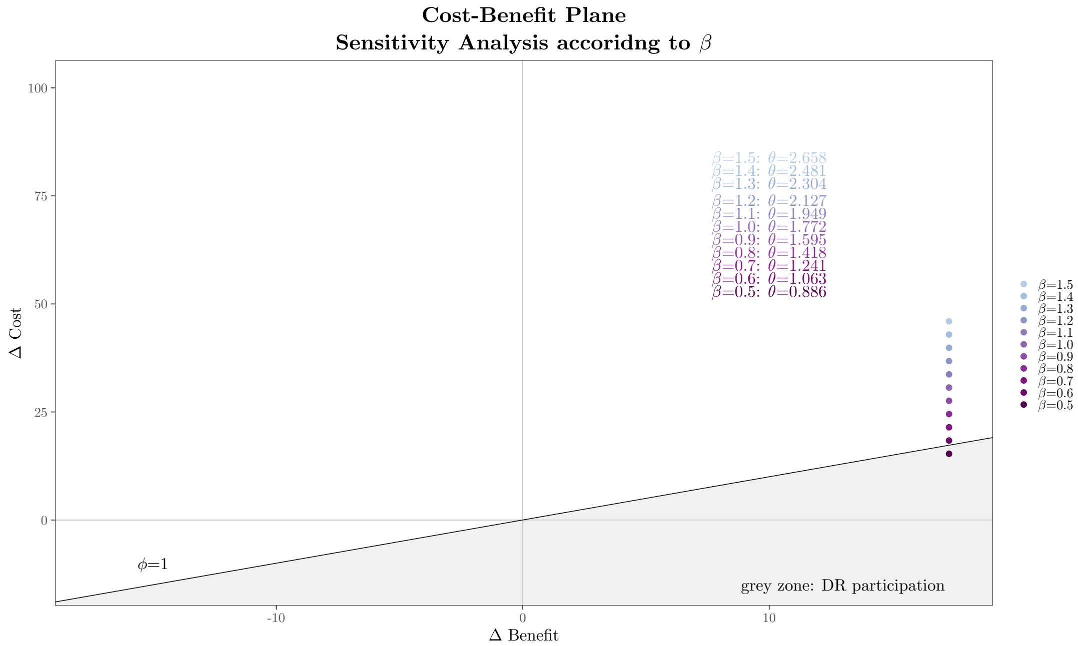


Figure 5: Sensitivity Analysis according to the Values of β (South Korean DRTM)

As can be seen in Figure 6, 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 appreciate the value of 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.

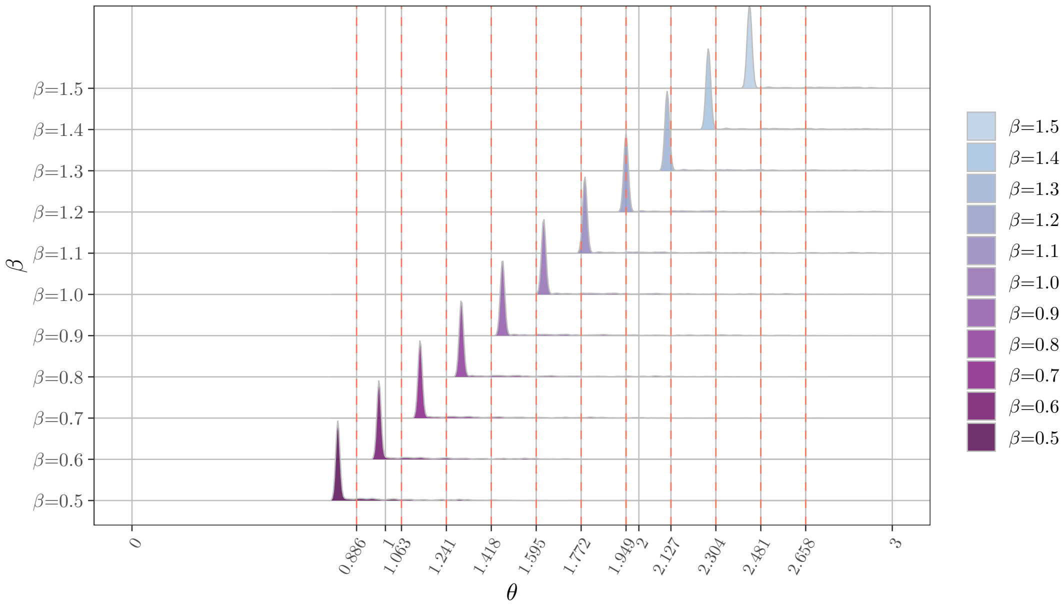


Figure 6: The Distribution of the θ Value for Each β Level (South Korean DRTM)

The values of θ are also verified according to the change of the tariff scheme from the uniform to the ToU tariff scheme (Box 3). Compared to the previous case with the uniform tariff scheme (Fig. 5), 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 pricing differentiation between the off-peak period and peak period in terms of the tariff.

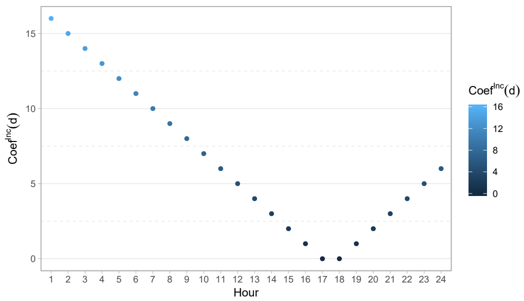
Box 3: Assumption Changes from 'Reference Scenario': Tariff Scheme (South Korean DTRM)

3. Tariff scheme: • uniform tariff scheme both for No DR participation and DR participation • 0.124 ₩/Wh, $\mathbf{p^u} = c = 0.124$, $t \in T = \{1, 2, \ldots, 24\}$	$\Rightarrow$	3. Tariff scheme: • Time-ou-Use (ToU) tariff scheme both for No DR participation and DR participation • $\mathbf{p^{tou}} = p_t^{tou}$, $t \in T = \{1, 2, \ldots, 24\}$

This time, the functional form of the inconvenience function has been changed from the linear to the exponential function based on the ToU tariff scheme (Box 4). 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: Assumption Changes from 'Reference Scenario': Different Form of Function $\text{Coef}^{\text{INC}}(\mathbf{d})$ based on ToU (South Korean DTRM)

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



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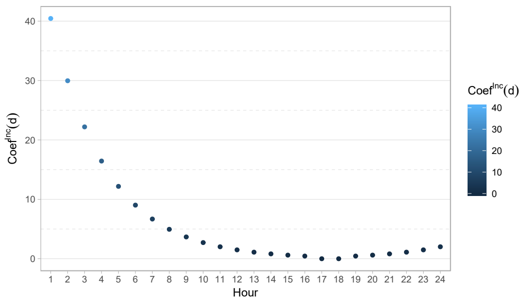
4. Inconvenience costs:
   - $\beta = 0.5$–1.5, by 0.1
   - exponential function of $\mathbf{Coef}^{\mathbf{INC}}(\mathbf{d})$



So far the CBAs have been done 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, the SAs have been conducted with the highest SMPs and the lowest SMPs in 2016 in order to confirm its sensitivity (Box 5). 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). With the lowest SMPs it decreased the benefits, and the points moved in the opposite direction—leftward horizontal shifts. As a result, no point is in the grey DR participation zone.

Box 5: Assumption Changes from 'Reference Scenario': Highest & Lowest SMPs (South Korean DTRM)

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

⇒

5. SMP:
   - Highest SMPs (2016-01-27)
   - Lowest SMPs (2016-02-08)

The following Figure 7 illustrates the SMP that makes the net benefit 0, zero, for each β value in the 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 Net Benefit Test Price or Net Benefit Threshold Price (NBTP) introduced in the 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 Net Benefit Test (NBT), LAs cannot bid below NBTP in the 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.[12]

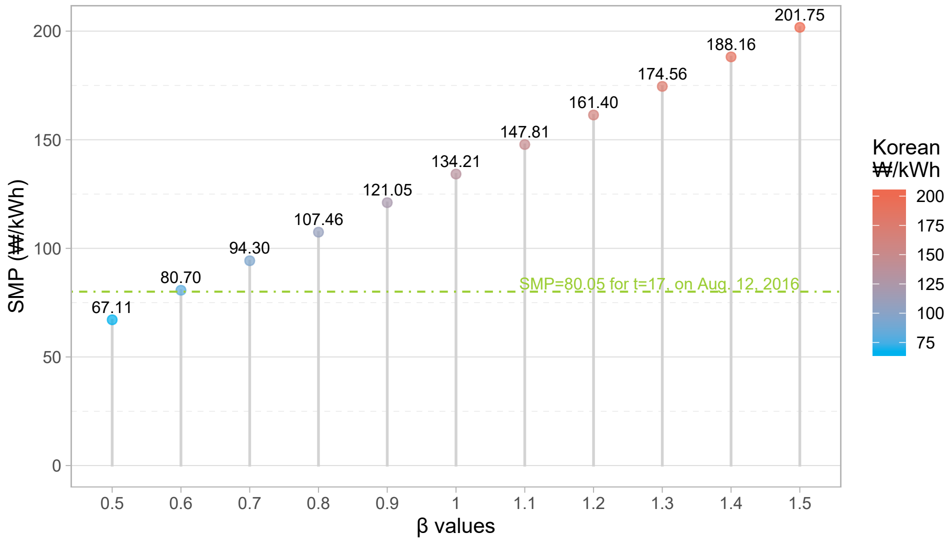


Figure 7: Threshold SMP of Net Benefit for Each β Value (South Korean DRTM, ₩/kWh)

Following the CBA and Decision-making analysis for the French NEBEF mechanisms, SAs have been 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. 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 6). In the upper panel of Figure 8 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 6: Assumption Changes from 'Reference Scenario': Inconvenience Costs (French NEBEF)

4. Inconvenience costs: • $\beta = 0.5$	⇒	4. Inconvenience costs: • $\beta = 0.5$–1.5, by 0.1

[12] In the South Korean DRTM, 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, NBT, which was introduced earlier in the U.S., 2011 by the FERC Order No. 745 [15], is introduced in South Korean DRTM. NBTP is the result of the NBT, and LAs cannot bid below this threshold price in South Korean DRTM [22].

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.

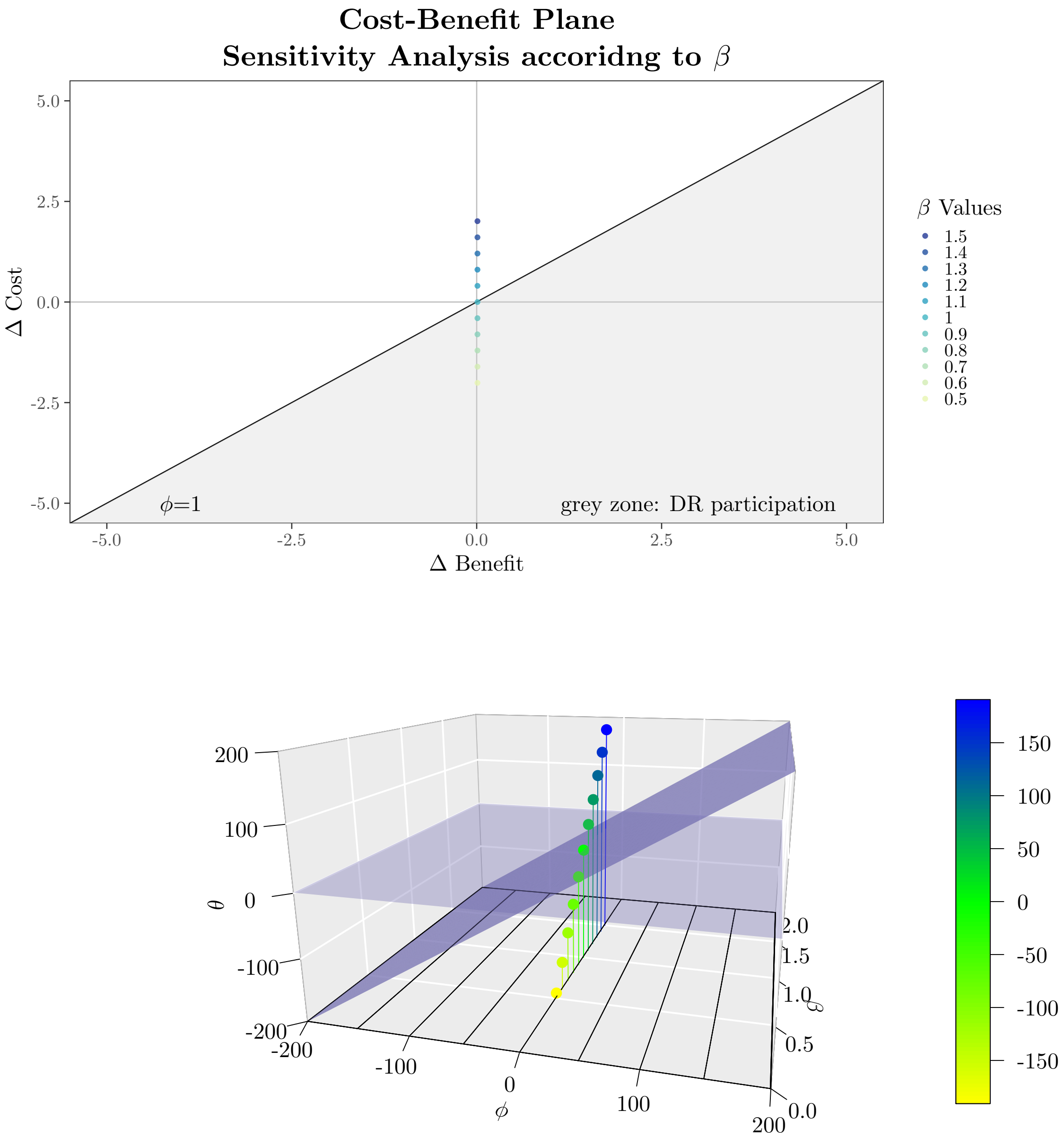


Figure 8: Sensitivity Analysis according to the Values of β for NEBEF (Load Shedding)

In the following Figure 9 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 away further from the grey zone.

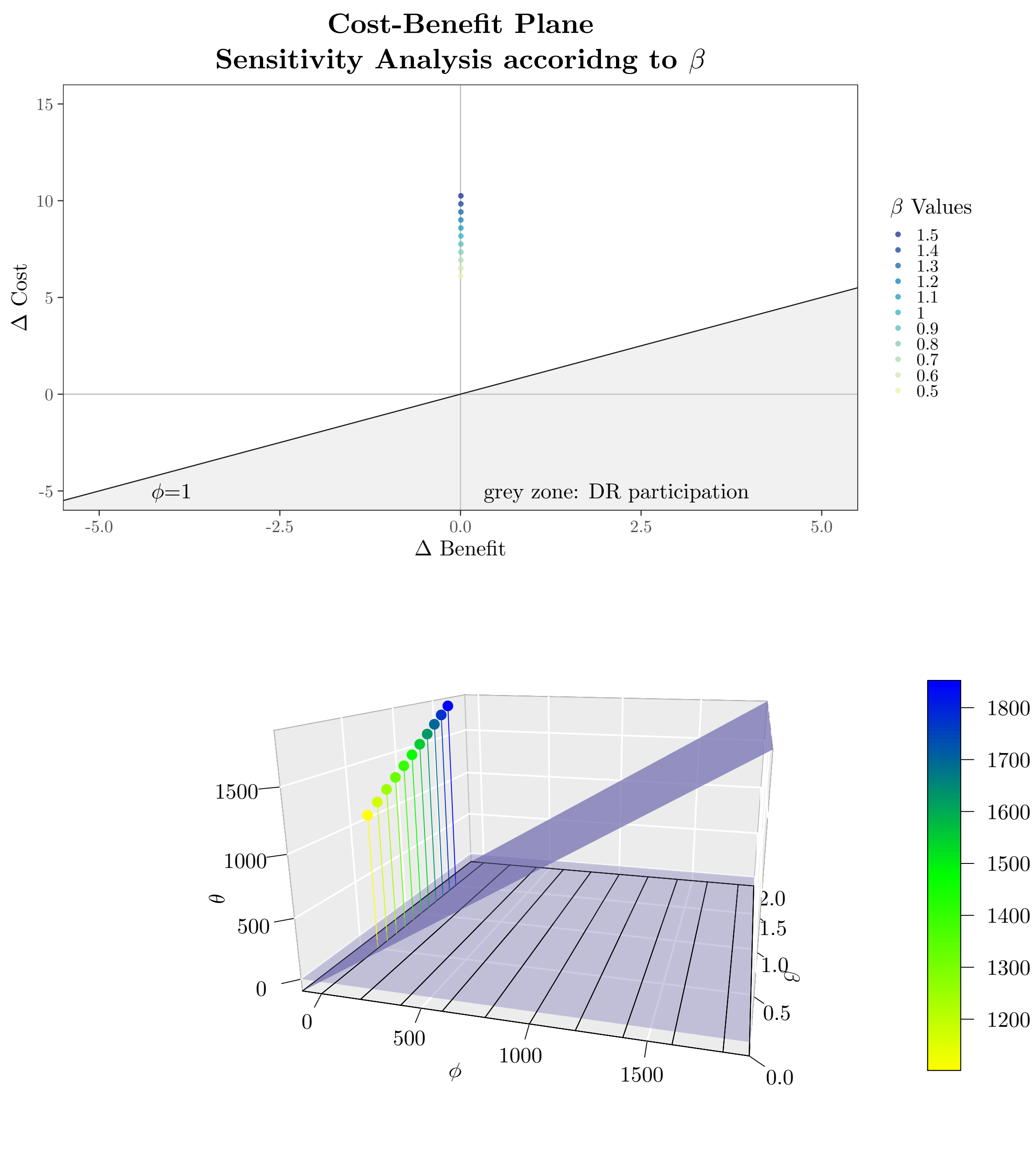


Figure 9: Sensitivity Analysis according to the Values of β for NEBEF (Load Shifting)

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.

In the previous sections, 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 a high error rate contrary to the CBL estimation method which is utilized in South Korea, which is $\text{CBL}^{\text{WMA}} + \text{SAA}$. 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 7).

Box 7: Assumption Changes from 'Reference Scenario': CBL (French NEBEF)

2. CBL estimation method:		2. CBL estimation method:
• $\text{CBL}^{\text{avg.10}}$	⇒	• $\text{CBL}^{\text{WMA}} + \text{SAA}$

The following Figure 10 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 $\text{CBL}^{\text{WMA}} + \text{SAA}$. 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 in the grey zone from out of the grey zone. For the load shifting case of NEBEF, despite of 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.

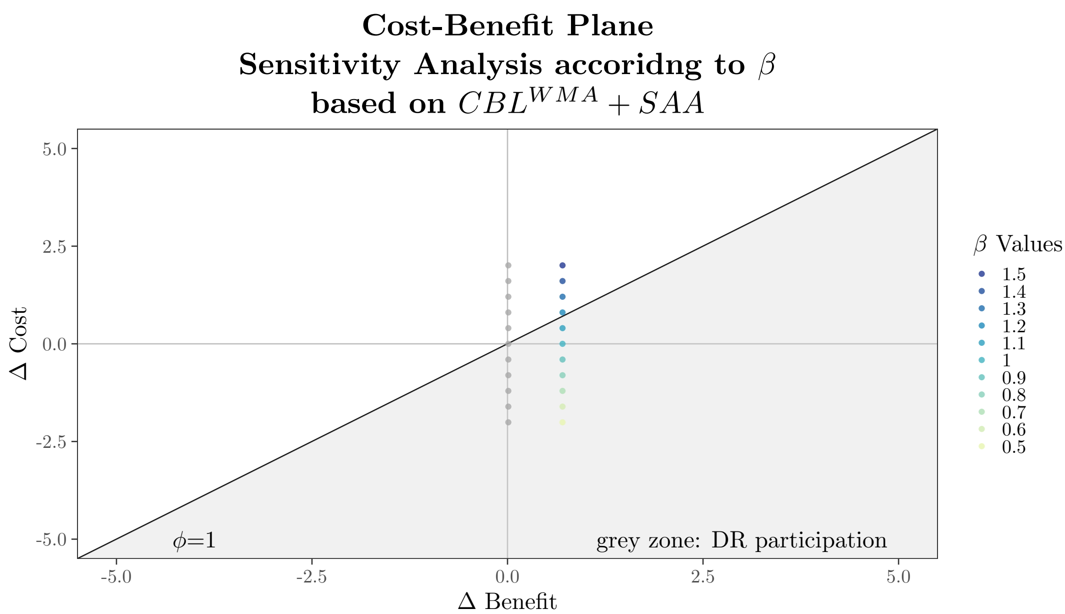


Figure 10: Sensitivity Analysis according to the Values of β for NEBEF (Load Shedding) based on the $\text{CBL}^{\text{WMA}} + \text{SAA}$ Method

As changed from the uniform tariff scheme to the ToU tariff scheme (Box 8), there are subtle downward vertical shifts for the eleven points due to tiny decrease in costs, but no significant impacts of the tariff scheme change both for the load shedding and load shifting cases of NEBEF.

Box 8: Assumption Changes from 'Reference Scenario': Tariff Scheme (French NEBEF)

3. Tariff scheme: • uniform tariff scheme • 0.01648 cts €/Wh, $\mathbf{p^u} = c = 0.01648$, $t \in T = \{1, 2, \ldots, 48\}$	$\Rightarrow$	3. Tariff scheme: • ToU tariff scheme • 0.016 cts €/Wh for peak time • 0.01114 cts €/Wh for off-peak time

For the combined impacts (Box 9) of the change of the CBL estimation method and the tariff scheme for the load shedding case of NEBEF, 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, for the load shifting case of NEBEF, the combined impacts of the CBL estimation method and the change of the tariff scheme show the diagonal shifts (Fig. A.1 in Appendix). 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.

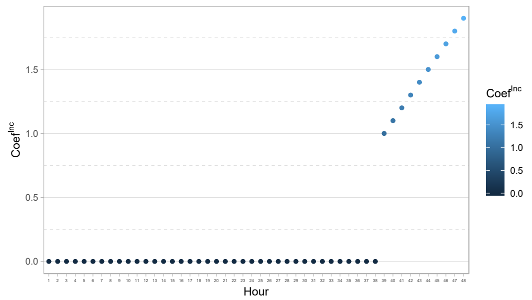
Box 9: Assumption Changes from 'Reference Scenario': CBL & Tariff Scheme (French NEBEF)

2. CBL estimation method: • $\text{CBL}^{\text{avg.10}}$	$\Rightarrow$	2. CBL estimation method: • $\text{CBL}^{\text{WMA}} + \text{SAA}$
3. Tariff scheme: • uniform tariff scheme • 0.01648 cts €/Wh, $\mathbf{p^u} = c = 0.01648$, $t \in T = \{1, 2, \ldots, 48\}$	$\Rightarrow$	3. Tariff scheme: • ToU tariff scheme • 0.016 cts €/Wh for peak time • 0.01114 cts €/Wh for off-peak time

For the impacts of the change of the inconvenience costs' functional form from linear to exponential function (Box 10), it is relevant only for the load shifting case like the South Korean DRTM. Unlike the South Korean case, this time, there was small impacts—small downward vertical shift and still out of the DR participation zone (Fig. A.2 in Appendix).

Box 10: Assumption Changes from 'Reference Scenario': Different Form of Function Coef^{INC} based on ToU Tariff Scheme (French NEBEF)

4. Inconvenience costs:
   - $\beta = 0.5$–1.5, by 0.1
   - linear function of Coef^{INC}



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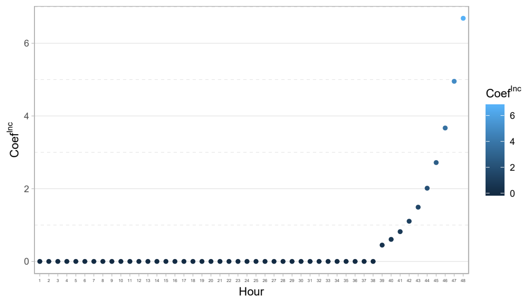
4. Inconvenience costs:
   - $\beta = 0.5$–1.5, by 0.1
   - exponential function of Coef^{INC}



Lastly, the impact of the change of the SMPs has been confirmed with the highest and lowest SMPs in 2016 based on the more accurate CBL estimation method ($\text{CBL}^{\text{WMA}} + \text{SAA}$) (Box 11). Like the South Korean case, with the highest SMPs, there were very significant impacts shifting the points to the right horizontally both for load shedding and load shifting 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 and load shifting cases.

Box 11: Assumption Changes from 'Reference Scenario': Highest & Lowest SMPs (French NEBEF)

5. SMP:
   - SMPs of DR event day (2016-01-18)

⇒

5. SMP:
   - Highest SMPs (2016-11-07)
   - Lowest SMPs (2016-05-29)

In terms of the SMP that makes the net benefit 0, zero, for each β value in the case of load shedding, French NEBEF, 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 (Fig. A.3 in Appendix). For those who have the value of $\beta = 0.5, 0.6, 0.7$, the thresholds are negative, so as long as the SMPs are positive, 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 the case of load shifting, French NEBEF, the SMPs that make the net benefit 0, are way higher than those of the load shedding case, French NEBEF—ranged from 299.07 €/MWh for $\beta = 0.5$ to 473.29 €/MWh for $\beta = 1.5$. Table 1 summarizes all the results of SAs according to each key parameter change.

Table 1: 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
$\mathbf{Coef}^{\mathbf{INC}}$ 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

V. CONCLUSIONS AND IMPLICATIONS

In this study, 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 [25]. 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 $\text{CBL}^{\text{avg.10}}$, there were too tiny net benefits, but with the accurate CBL estimation method $\text{CBL}^{\text{WMA}}+\text{SAA}$, we observed the significant and positive horizontal shift with increased net benefits. From the DR system operator, 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. 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, 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.

Like the importance of the coefficient β, the importance of the functional form of $\textbf{Coef}^{\textbf{INC}}$ was confirmed. Whether one participant's functional form of $\textbf{Coef}^{\textbf{INC}}$ 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 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. 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' $\mathbf{v}$ (transfer), 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 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, the peak days were chosen for the DR event days 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 on 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.

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APPENDICES

A. SUPPLEMENTARY FIGURES

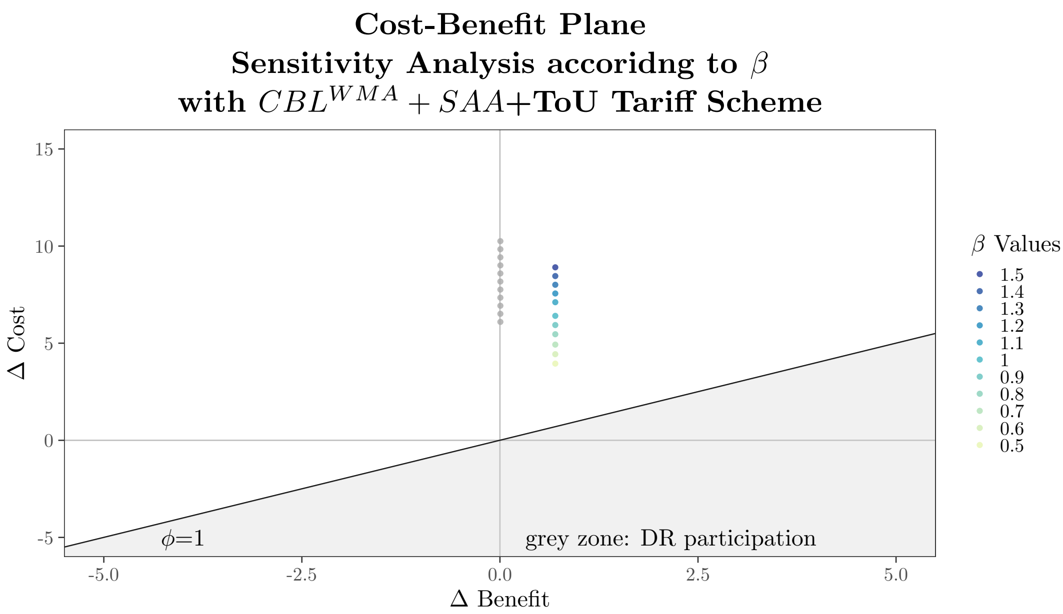

Figure A.1: Sensitivity Analysis according to the Values of β for NEBEF (Load Shifting) with $\text{CBL}^{\text{WMA}} + \text{SAA}$ & ToU Tariff Scheme

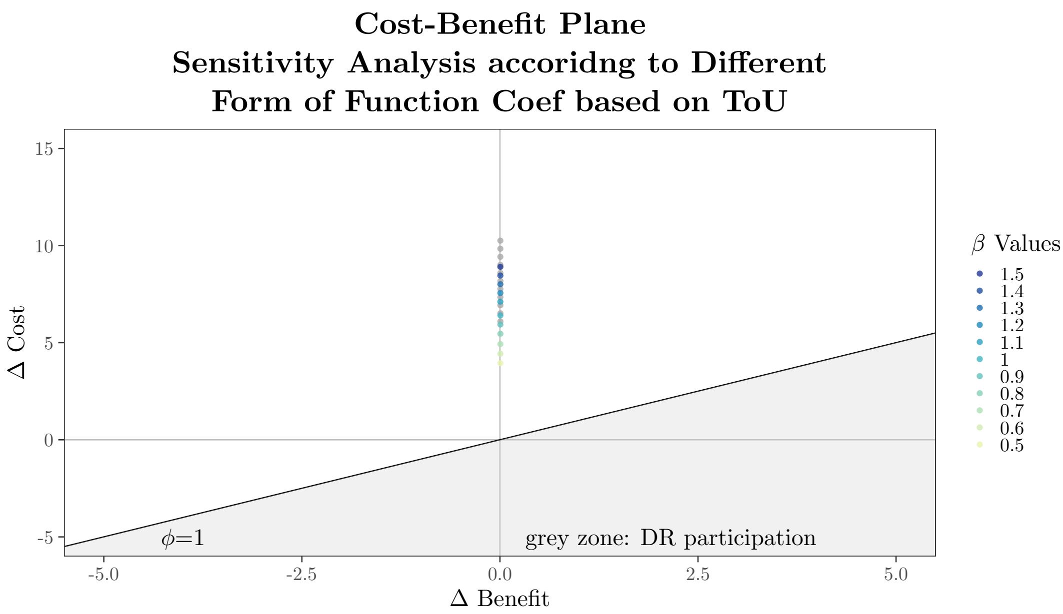

Figure A.2: Sensitivity Analysis according to the Different Form of Function Coef^{INC} based on ToU Tariff Scheme (Load Shifting, French NEBEF)

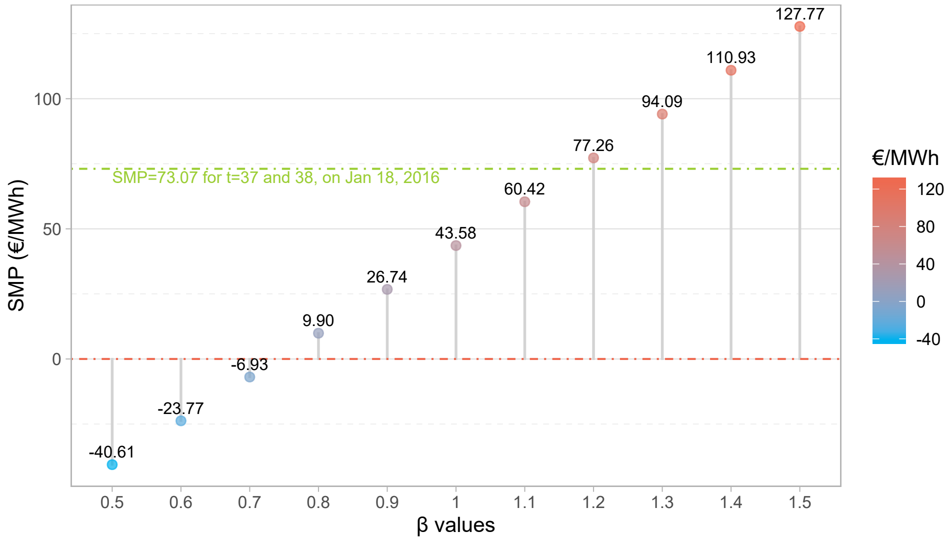

Figure A.3: Threshold SMP of Net Benefit for Each β Value (Load Shedding, French NEBEF, €/MWh)

B. SUPPLEMENTARY EQUATIONS

$$
\begin{aligned}
\max_{\mathbf{x}} \Pi(\mathbf{x}; \phi, \mathbf{SMP}, \mathbf{r}', \mathbf{p}, \boldsymbol{\ell}') =& B(\phi, \mathbf{SMP}, \mathbf{r}') - C(\mathbf{x}; \mathbf{p}, \boldsymbol{\ell}') \\
=& f_o(x_1, x_2, \ldots, x_{24}; \phi, \mathrm{SMP}_{17}, \mathrm{SMP}_{18}, r'_{17}, r'_{18}) \\
or,\ \min_{\mathbf{x}} C(\mathbf{x}) =& f_o(x_1, x_2, \ldots, x_{24})
\end{aligned}
\tag{B.1}
$$

where,

- $\mathbf{x}$: a column vector consisting of the proportions to the total required load reduction that will be shifted to other time slots, $t \in T = \{1, 2, \ldots, 24\}$, 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-ϕ), $0 \leq \phi \leq 1$
- $\mathbf{SMP}$: a vector of SMP,
- $\mathbf{r}'$: a vector of actualized load reduction,
- $\mathbf{p}$: retail price of electricity (tariff scheme),
- $\boldsymbol{\ell}'$: a column vector consisting of the actually consumed loads with DR for each time slot, $t \in T = \{1, 2, \ldots, 24\}$, if we consider only load shifting, not load shedding, then the total electricity consumptions remain the same with DR event and without DR event, $\mathbf{1}_{24}^T \boldsymbol{\ell} = \mathbf{1}_{24}^T \boldsymbol{\ell}'$ 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.

. . . .

subject to the constraints,

$$\begin{cases} \sum_{t=1}^{24} x_t = 1 \\ x_{17}, x_{18} = 0 \\ x_1, x_2, \ldots, x_{16}, x_{19}, x_{20}, \ldots, x_{24} \geq 0 \\ x_1, x_2, \ldots, x_{16}, x_{19}, x_{20}, \ldots, x_{24} \leq \frac{\mathrm{Cap}_t}{(r_{17} + r_{18})} \cdot \ell_t \end{cases} \tag{B.2}$$

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 '0' and Required Flexibility Level (RFL),
$\mathbf{Cap} \sim U(0, \mathrm{RFL})$
$0 \leq \mathrm{Cap}_t \leq \mathrm{RFL}$
$t \in T = \{1, 2, \ldots, 24\}$

RFL : reuiqred flexibility level, such as, 0.2 (20%), 0.3 (30%), 0.4 (40%), or 1 (max).

. . . .

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

$$\mathbf{r} = r_t = \begin{pmatrix} r_1 \\ \vdots \\ r_{16} \\ r_{17} \\ r_{18} \\ r_{19} \\ \vdots \\ r_{24} \end{pmatrix} = \begin{pmatrix} 0 \\ \vdots \\ 0 \\ r_{17} \\ r_{18} \\ 0 \\ \vdots \\ 0 \end{pmatrix} \tag{B.3}$$

where,

r : a column vector consisting of the required load reductions for each time slots, especially, for the DR event times,
$r_{17} \geq 0, r_{18} \geq 0,\ r_1 = r_2 = \cdots = r_{16} = r_{19} = \cdots = r_{24} = 0.$

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

$$\boldsymbol{\ell} = \ell_t = \begin{pmatrix} \ell_1 \\ \ell_2 \\ \vdots \\ \ell_{17} \\ \ell_{18} \\ \vdots \\ \ell_{24} \end{pmatrix} \tag{B.4}$$

where,

$$\begin{cases} \boldsymbol{\ell} : & \text{a column vector consisting of the actually consumed loads without the DR event for each time slot, } t \in T = \{1, 2, \ldots, 24\}. \end{cases}$$

. . . .

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 $t = 18h$.

$$\begin{aligned} \boldsymbol{\ell}' = \ell'_t = \begin{pmatrix} \ell'_1 \\ \ell'_2 \\ \vdots \\ \ell'_{17} \\ \ell'_{18} \\ \vdots \\ \ell'_{24} \end{pmatrix} &= \boldsymbol{\ell} - \mathbf{r} + (r_{17} + r_{18})\mathbf{x} \\ &= \begin{pmatrix} \ell_1 \\ \vdots \\ \ell_{16} \\ \ell_{17} \\ \ell_{18} \\ \ell_{19} \\ \vdots \\ \ell_{24} \end{pmatrix} - \begin{pmatrix} 0 \\ \vdots \\ 0 \\ r_{17} \\ r_{18} \\ 0 \\ \vdots \\ 0 \end{pmatrix} + (r_{17} + r_{18}) \begin{pmatrix} x_1 \\ \vdots \\ x_{16} \\ 0 \\ 0 \\ x_{19} \\ \vdots \\ x_{24} \end{pmatrix} \end{aligned} \tag{B.5}$$

. . . .

Let us define a column vector of **CBL**′ in which all the elements are ‘0’ (zero) except 17^{th}

and 18^{th} elements, and those are CBL_{17} and CBL_{18}, respectively,

$$\mathbf{CBL}' = \begin{array}{c} \scriptstyle 1 \\ \scriptstyle 2 \\ \vdots \\ \scriptstyle 17 \\ \scriptstyle 18 \\ \vdots \\ \scriptstyle 24 \end{array} \begin{pmatrix} 0 \\ 0 \\ \vdots \\ \mathrm{CBL}_{17} \\ \mathrm{CBL}_{18} \\ \vdots \\ 0 \end{pmatrix} \tag{B.6}$$

. . . .

and a column vector of $\boldsymbol{\ell}''$ (double prime of $\boldsymbol{\ell}$) in which all the elements are '0' (zero) except 17^{th} and 18^{th} elements, and those are ℓ'_{17} and ℓ'_{18}, respectively.

$$\boldsymbol{\ell}'' = \begin{pmatrix} 0 \\ 0 \\ \vdots \\ \ell'_{17} \\ \ell'_{18} \\ \vdots \\ 0 \end{pmatrix} = \begin{pmatrix} 0 \\ 0 \\ \vdots \\ \ell_{17} \\ \ell_{18} \\ \vdots \\ 0 \end{pmatrix} - \begin{pmatrix} 0 \\ 0 \\ \vdots \\ r_{17} \\ r_{18} \\ \vdots \\ 0 \end{pmatrix} \tag{B.7}$$

. . . .

$$\mathbf{r}' = \mathbf{CBL}' - \boldsymbol{\ell}'' = \begin{pmatrix} 0 \\ 0 \\ \vdots \\ \mathrm{CBL}_{17} \\ \mathrm{CBL}_{18} \\ \vdots \\ 0 \end{pmatrix} - \begin{pmatrix} 0 \\ 0 \\ \vdots \\ \ell'_{17} \\ \ell'_{18} \\ \vdots \\ 0 \end{pmatrix} = \begin{pmatrix} 0 \\ 0 \\ \vdots \\ r'_{17} \\ r'_{18} \\ \vdots \\ 0 \end{pmatrix} \tag{B.8}$$

. . . .

The benefits from the remuneration will be the following (Eq. B.9):

$$B(\phi, \mathbf{SMP}, \mathbf{r}') = \phi \cdot \mathbf{SMP}^{\mathbf{T}} \cdot \mathbf{r}' = \phi \begin{pmatrix} \mathrm{SMP}_1 & \mathrm{SMP}_2 & \dots & \mathrm{SMP}_{24} \end{pmatrix} \begin{pmatrix} 0 \\ 0 \\ \vdots \\ r'_{17} \\ r'_{18} \\ \vdots \\ 0 \end{pmatrix} \tag{B.9}$$

where,

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

. . . .

$$C(\mathbf{x}) = \text{Total Tariff} + \text{Additional Inconvenience Costs (INC)} \tag{B.10}$$

. . . .

$$\mathbf{p^u} = \; p_t^u \; = \begin{pmatrix} c \\ c \\ \vdots \\ c \end{pmatrix}, \quad \mathbf{p^{tou}} = \; p_t^{tou} \; = \begin{pmatrix} p_1 \\ p_2 \\ \vdots \\ p_{24} \end{pmatrix} \tag{B.11}$$

where,

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

$$\mathbf{d} = d_t = \begin{pmatrix} d_1 \\ d_2 \\ \vdots \\ d_{16} \\ d_{17} \\ d_{18} \\ d_{19} \\ \vdots \\ d_{24} \end{pmatrix} = \begin{pmatrix} 16 \\ 15 \\ \vdots \\ 1 \\ 0 \\ 0 \\ 1 \\ \vdots \\ 6 \end{pmatrix} \tag{B.12}$$

where,

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

$$\mathrm{INC}_t = \beta \frac{(p_{17} + p_{18})}{2} d_t (r_{17} + r_{18}) x_t \tag{B.13}$$

$$\mathbf{INC} = \begin{pmatrix} \mathrm{INC}_1 \\ \mathrm{INC}_2 \\ \vdots \\ \mathrm{INC}_{24} \end{pmatrix} = \beta \frac{(p_{17} + p_{18})}{2} (r_{17} + r_{18}) \cdot diag(\mathbf{d} \otimes \mathbf{x}) \tag{B.14}$$

where,

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

$$\mathbf{d} \otimes \mathbf{x} = \mathbf{d} \cdot \mathbf{x}^{\mathbf{T}} = \begin{pmatrix} d_1 \\ d_2 \\ \vdots \\ d_{24} \end{pmatrix} \begin{pmatrix} x_1 & x_2 & \dots & x_{24} \end{pmatrix}$$

$$= \begin{pmatrix} d_1 x_1 & d_1 x_2 & \dots & d_1 x_{24} \\ d_2 x_1 & d_2 x_2 & \dots & d_2 x_{24} \\ \vdots & \vdots & \ddots & \vdots \\ d_{24} x_1 & d_{24} x_2 & \dots & d_{24} x_{24} \end{pmatrix} \tag{B.15}$$

$$diag(\mathbf{d} \otimes \mathbf{x} = \mathbf{d} \cdot \mathbf{x}^{\mathbf{T}}) = \begin{pmatrix} d_1 x_1 \\ d_2 x_2 \\ \vdots \\ d_{24} x_{24} \end{pmatrix}$$

$$\text{Total INC} = \beta \frac{(p_{17} + p_{18})}{2} (r_{17} + r_{18}) \mathbf{d}^{\mathbf{T}} \cdot \mathbf{x} \tag{B.16}$$

....

$$\begin{aligned} &\max_{\mathbf{r}} \Pi(\mathbf{r}; \phi, \mathbf{r}', \mathbf{SMP}, \mathbf{v}, \beta, \mathbf{Coef}^{\mathbf{INC}}) = B(\phi, \mathbf{r}', \mathbf{SMP}, \mathbf{v}) - C(\mathbf{r}; \beta, \mathbf{Coef}^{\mathbf{INC}}) \\ =& f_o(r_{37}, r_{38}; \phi, r'_{37}, r'_{38}, \mathrm{SMP}_{37}, \mathrm{SMP}_{38}, v_{37}, v_{38}, \beta, \mathrm{Coef}_{37}^{\mathrm{INC}}, \mathrm{Coef}_{38}^{\mathrm{INC}}) \end{aligned} \tag{B.17}$$

....

$$\begin{aligned} &\max_{\mathbf{r},\mathbf{x}} \Pi(\mathbf{r}, \mathbf{x}; \phi, \mathbf{r}', \mathbf{SMP}, \beta, \mathbf{p}, \mathbf{Coef}^{\mathbf{INC}}) = B(\phi, \mathbf{r}', \mathbf{SMP}, \mathbf{v}) - C(\mathbf{r}, \mathbf{x}; \beta, \mathbf{p}, \mathbf{Coef}^{\mathbf{INC}}) \\ =& f_o(r_{37}, r_{38}, x_1, x_2, \dots, x_{48}; \phi, r'_{37}, r'_{38}, \mathrm{SMP}_{37}, \mathrm{SMP}_{38}, v_{37}, v_{38}, p_{37}, p_{38}, \mathrm{Coef}_{37}^{\mathrm{INC}}, \mathrm{Coef}_{38}^{\mathrm{INC}}) \end{aligned} \tag{B.18}$$

....

$$\max_{\mathbf{x}} \Pi_1(\mathbf{x}; \phi, \mathbf{SMP}, \mathbf{r}', \mathbf{p}, \boldsymbol{\ell}') - \max_{\mathbf{x}} \Pi_0(\mathbf{x}; \phi, \mathbf{SMP}, \mathbf{r}', \mathbf{p}, \boldsymbol{\ell}') > 0 \tag{B.19}$$

....

$$\begin{cases} \text{If, } \phi > \theta & \Rightarrow \text{ DR Participation,} \\ \text{If, } \phi < \theta & \Rightarrow \text{ No DR Participation,} \\ \text{If, } \phi = \theta & \Rightarrow \text{ No Difference (indifferent).} \end{cases} \tag{B.20}$$

where,

$$\begin{cases} \phi & : \text{the proportion to SMP for a residential participant, therefore,} \\ & \quad \text{the proportion to SMP for a LA is } (1\text{-}\phi), \\ & \quad 0 \leq \phi \leq 1 \\ \theta & : \text{ratio of the cost differential } (\Delta C) \text{ over the benefit differential} \\ & \quad (\Delta B) \text{ between two cases, DR participation and no DR parti-} \\ & \quad \text{ciation (status quo),} \\ & \quad \frac{\Delta(C_1 - C_0)}{\Delta(B_1 - B_0)} = \frac{\Delta C}{\Delta B}. \end{cases}$$

. . . .