IET Generation, Transmission & Distribution

Research Article

Demand response procurement framework: a new four-step probabilistic method

ISSN 1751-8687
Received on 23rd April 2019
Revised 10th October 2019
Accepted on 12th November 2019
E-First on 16th December 2019
doi: 10.1049/iet-gtd.2019.0628
www.ietdl.org

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Abstract: This study presents a new market-driven and transparent pricing mechanism for demand response (DR) that ensures social welfare is maximised. The existing methods have DR priced at the electricity market clearing price (EMCP), where the EMCP is determined in a market solely comprised of aggregated generator price bids and demand bids. DR supply bids are not included in the current economic market model, resulting in inefficient markets. The authors also present a new metric, Actual Price, which captures two key elements missed by EMCP: (a) the price paid to DR suppliers (EMCP covers only the price paid to generators); and (b) the reduced pool of paying consumers when DR suppliers leave the buyer pool. An implementable process for DR planning using the authors' new concepts is presented. Results are shown for systems with and without location pricing. The results demonstrate that the proposed DR procurement method yields lower Actual Prices than existing methods and results in savings for customers. These ideas can guide regulators in determining market-based pricing policies for DR as well as Independent System Operators and system operators in determining DR procurement levels.

Nomenclature

Parameters

a, b, c, d	constants for generator cost and price bid curves
NH	number of time periods
e, f, g	constants for demand response (DR) resource price bid curve
NB	total number of buses
NT	total number of transmission lines and transformers
KD_i	price bid by demand at bus i
KG_i	price bid by generators at bus i
$\overline{V_i}, \underline{V_i}$	maximum and minimum voltages at bus i
$Y_{ij}\angle\theta_{ij}$	bus admittance matrix element between buses i and j
$y_{ij}\angle\phi_{ij}$	line admittance element between buses i and j
$\overline{PG}, \underline{PG}$	maximum and minimum generation limits of all system generators combined
$\overline{PRS_m}$	maximum limit for DR supplier m
$\overline{SF_k}$	maximum apparent power flow possible in line k
λPRS_m	bid price for DR supplier m
PRS_m	quantity offered by DR supplier m
PD	total system demand from all loads
p_h	duration of time period h per year, as a percentage
T_h	duration of time period h per year, in hours

Indices

i, j	bus indices
k	transmission line and transformer index
m	DR supplier index

Variables

PG	total generation produced by all generators
$F(PG)$	Aggregate generator cost at PG
$PR, \overline{PR}$	total and optimal quantity of DR dispatched
PR_{EXP}	expected value of DR quantity
PRS, PRD	total DR resources offered and demanded
BCG	buyers' cost for generation
BCR	buyers' cost for DR
$\lambda(PG)$	aggregate generator price bid at PG
$\lambda 0$	market-clearing price with no DR
λN	price paid to generators, with PR
λA	actual price for remaining consumers, with PR
λPRD	maximum price remaining consumers are willing to pay for PRD of DR
λPRS	minimum price DR service providers are willing to accept for PRS of DR
$\lambda PR, \overline{\lambda PR}$	price and optimal price for PR
NDR	total number of DR bids dispatched
$V_i\angle\delta_i$	voltage phasor at bus i
PG_i, QG_i	real and reactive power generated at bus i
PD_i, QD_i	real and reactive power consumed at bus i
SF_{ki}, SF_{kj}	apparent power flow in line k from buses i and j, respectively

1 Introduction

1.1 Motivation

Demand response (DR) has been gaining prominence in recent years, as the advent of more accessible smart grid technologies opens new possibilities for reaping benefits from DR. By definition, DR is 'changes in electric usage by demand-side resources from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardised' [1].

This paper contributes to the maturing of theory used for modelling, pricing and managing DR by proposing a systematic method with clearly defined metrics to objectively and scientifically demonstrate maximum benefits of DR to electricity consumers and DR vendors. This procurement strategy holistically and fully considers the economic consequences of DR and then deploys DR to lower Actual Prices for electricity. This enables Independent System Operators (ISOs) to procure DR in the most efficient manner.

1.1.1 FERC Order 745: On 15 March 2011, the Federal Energy Regulatory Commission (FERC) issued Order 745, 'Demand Response Compensation in Wholesale Energy Markets.' Order 745 asserts two key requirements relevant for this work: (a) that DR

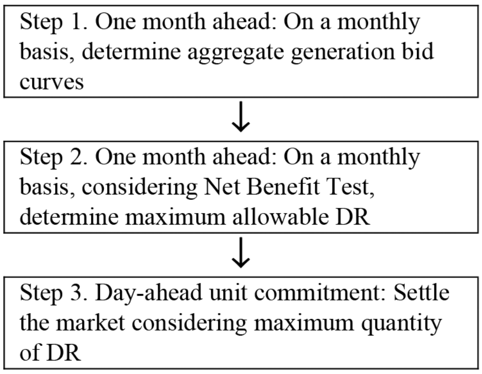

Fig. 1 *DR procurement procedure for California ISO*

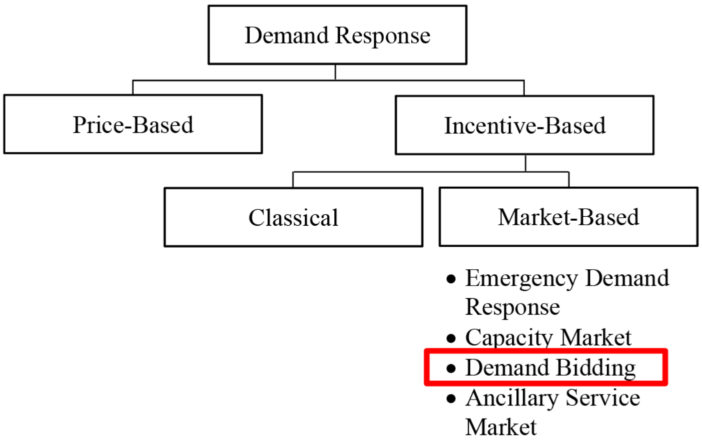

Fig. 2 *DR categories and sub-categories*

purchases pass a Net Benefits Test (NBT); and (b) that DR services are paid at the Energy Market Clearing Price (EMCP) [2].

First, the NBT makes sure that the collective benefits of DR to buyers outweigh the costs of DR. While the NBT is a step in the right direction, it does not ensure that consumers benefit from optimal rates for DR – it only ensures that consumers would not be worse off with DR than they would have been without DR. In this paper, we use an optimised method that will deliver the most favourable benefits to consumers, while satisfying the minimum required under FERC Order 745. It considers the concept of the Actual Price of electricity, which accounts for both the costs of DR and the shrunken consumer pool.

Second, the FERC framework in Order 745 specifies that DR services are paid at the EMCP. In its consultations in developing Order 745, FERC heard arguments debating the merits of setting the price paid to DR at EMCP or at some other rate. The discussions covered fairness, relative contributions of DR and generators, and administrative burdens of implementation, among other items. The debate did not cover the impact of DR on the Actual Prices paid by remaining consumers.

However, ascertaining the true value of DR for the remaining consumers requires a clear understanding of the economic interdependences between Actual Prices of electricity, DR prices, and DR quantities. This, in turn, allows ISOs to determine the best price to pay for DR services based purely on the best interests of remaining consumers. This requires the demand curve for DR, and we propose a method to create this demand curve for DR in this paper.

In the literature, the implementation of NBT itself is absent. Thus, the next stage of optimising NBT is obviously not considered.

With the release of FERC Order 745, jurisdictions such as the California ISO devised a procedure that procures DR Service via a process as shown in Fig. 1 [3]. It outlines the basics steps for DR procurement.

Our proposed method enhances the existing method used by the California ISO by using a market-determined price for DR, accounting for fluctuations in supply and demand in both energy and DR services and extending it for planning purposes.

1.2 Literature review

There are multiple schemes that fall under the umbrella of DR. As shown in Fig. 2, DR can be categorised into two broad categories: incentive-based DR and price-based DR [4–7]. Demand bidding programs, which we explore in this paper, and which encompass the DR under FERC Order 745, fall under the market-based incentive sub-category of DR.

Price-based DR motivates loads to adjust their consumption levels in response to price signals. Research in this area includes an algorithm to resolve the many-to-one matching game for data centres and utilities with which they can enter bilateral contracts, resulting in lower costs for participating data centres and higher revenues for utilities that offer lower rates [8]. Another study proposes a decentralised DR framework in which both DR providers' confidential discomfort and generators' costs are jointly minimised [9]. Conversely, DR resources can make their intentions known in programs that allow them to place bids [10]. In any case, greater incorporation of price-based DR in Regional Transmission Organization wholesale markets requires substantial policy changes [11]. Furthermore, price-based DR has been shown to increase EMCP in some systems [12].

Incentive-based DR participants are given rewards or discounts for adjusting their usage, whereas price-based DR consumers change their consumption in reaction to changes in retail prices [13]. Within the incentive-based DR category, there is no standard method of offering incentives, which could be a financial payment, discount, related to capacity or energy, or something else. In this paper, we devise a method to determine the value of the incentive that should be paid in order to minimise the Actual Prices of electricity for remaining consumers.

In academic literature, there are a variety of approaches for incentive-based DR procurement for wholesale energy markets relating to (a) the price at which DR is compensated; (b) the optimisation objective of the procurement method; and (c) the way in which performance and impact are measured.

First, DR has been compensated at various rates. A pre-determined price was used as an input parameter to help manage the intermittent nature of renewable energy [14] and for energy service providers [15]. Another study pays DR at their bid-offer prices [16]. Still another approach is to compensate DR services at the energy market clearing price, which is consistent with FERC Order 745 [17]. In Texas, the Electric Reliability Council of Texas found that offering capacity payments to dispatched DR through their balancing up load program was insufficient to entice participants in this program [18].

To our knowledge, there have been only two recently published studies that questioned and explored the appropriate pricing level of DR demand bidding. The first study, which creates a DR supply curve was based on exploiting the differences between wholesale and retail prices, yielding optimal DR prices and quantities, as an alternative to FERC Order 745 [19]. The second proposed scheme iterates through different DR prices until the objective has been reached. However, this study also uses DR to minimise losses incurred by the difference between wholesale and retail prices [20]. We build on both studies' findings here by optimising for the wholesale energy market first before accounting for disparities between wholesale and retail prices.

Second, two main common optimisation objectives for procurement methods have been employed in the literature. A common approach is optimising DR procurement by minimising total costs [14–16, 21, 22]. This method finds the Nash equilibrium in a single-ended auction with a single commodity. However, with DR, there are two commodities procured simultaneously, and the purchase of one of these commodities reduces the size of the paying pool of consumers. Therefore, minimising costs no longer maximises social welfare, which is the aim. Furthermore, this does not account for the fact that DR removes previously paying consumers from the pool. This results in a smaller pool of consumers sharing the total costs, so even if total costs are minimised, this does not necessarily mean that the rates paid by remaining consumers are minimised. Another study explicitly maximises social welfare [17], but does not take into account the change in demand due to DR. One study aims to reduce the peak load on a distribution feeder in a smart grid [23], while another aims to manage the variability caused by renewable energy sources [24]. Loss minimisation for utilities due to the gap between wholesale and retail prices has also been used as an objective [20].

Third, several performance measures for the proposed approaches have been used. Approaches include looking at total system operating costs [21, 22], total generation costs [14], marginal energy prices [17, 21], congestion in the system [17], and volatility [21]. Additionally, market design issues arise in accurately accounting for load reduction, which is based on past consumption [25]. This issue extends to most forms of DR. We will show that the complete metric of impact to remaining consumers is the Actual Price, which will be introduced in the next section.

DR procurement is important because ISOs need to know how much to pay for DR, the best way to procure DR, and how to measure DR's impact. We will build on these past studies to show the best way forward for all three aspects.

1.2.1 Demand curve for DR: In order to create a rigorous and systematic process for DR procurement, an accurate demand curve for DR must be used. This does not currently exist in practice or in the literature.

In practice, there is no demand curve specifically for DR for the energy markets – namely, real-time and day-ahead markets. There is the regular energy demand curve, for which load consumer bids are stacked from lowest to highest. However, this curve cannot be accurately used for markets that include both energy and DR because (a) DR service providers, by definition, are loads that convert to vendors, so there is a smaller resulting pool of consumers sharing the costs; and (b) costs paid to DR vendors are absent. In other words, the existing demand curve is for markets with only energy; it does not accurately account for markets with DR.

In the literature, a standard method for determining the appropriate incentives to pay incentive-based DR is lacking. In this paper, we devise a new market-based method to valuate DR for remaining consumers. This is represented by a new demand curve for DR. We also demonstrate how to harness market forces to settle the DR market – i.e. determining optimal DR prices and quantities – so that social welfare is maximised.

In order to understand the demand curve for DR, a metric to assess the impact of DR on consumers is required.

1.3 Contributions

In this paper, we present three main contributions that address the identified gaps in practice and in the literature:

(i) *Market-based DR price* – The novelty and centrepiece in our work is a new market-driven and transparent pricing mechanism for DR. The existing method (in the literature and under FERC Order 745) forces the price of DR service to be the same as the electricity market clearing price (EMCP) or λN, where EMCP is the price paid for delivering energy by generators and DR is a service and not delivery of energy. The EMCP is determined in a market solely comprising aggregated generator price bids and the demand bids, and EMCP is imposed upon DR vendors. The supply bids of DR are neither sought nor considered, and an economic model of DR vendors is completely disregarded. This disregard for an economic model of DR vendors results in their absence or inefficient participation in the electricity market, reducing the overall efficiency of the electricity market.

We overcome this shortcoming by creating a separate but connected market for DR, accepting bids from DR vendors and calculating the demand curve for DR buyers (the electricity market comprising generators and loads). This proposed DR market yields the optimal quantity and price for DR services and guarantees economic efficiency for the DR market, and accordingly, the electricity market.

(ii) *Actual Price* – We also present a new metric: Actual Price, which equals the price of electricity considering payments to generators for energy and DR vendors for service, considering the reduced customer base. It captures two key elements missed by EMCP or λN (the metric used today): (i) the costs paid to DR suppliers (EMCP covers only the price paid to generators); and (ii) the reduced pool of paying consumers when DR suppliers leave the buyer pool. Actual price is not found in literature, although the inadequacy of EMCP, when DR is scheduled, has been generally acknowledged for a long time in the industry [2].

(iii) *DR Planning Process* – We create a new, implementable 4-step process for DR planning. Our method of longer-term sourcing for DR fills a gap in the literature, like most works centre around shorter-term scheduling problems. It is a probabilistic model that accounts for the fluctuation in electricity market prices.

1.4 Organisation of this paper

The paper is organised as follows: The introduction is in Section 1, and it includes the motivation behind this work and the literature review.

Section 2 contains the methodology, including the introduction of Actual Price in Section 2.1, followed in Section 2.2 by an overview of the proposed DR procurement process. Step 1 (Section 2.3) segments the hourly energy market prices into several probable scenarios, computing the probability of occurrence for each scenario and the corresponding aggregated generator cost curve. Step 2 (Section 2.4) enhances the FERC NBT requirement to not only shield consumers from harm due to DR, but to also obtain the best possible outcomes. We achieve this by minimising the Actual Price of electricity. This minimisation yields the new DR demand curve, which articulates the optimal economic interdependence of DR quantity and DR price for remaining consumers. In Step 3 (Section 2.5), this DR demand curve, in conjunction with a DR offer bid curve, is then used to settle the DR market and determine optimal DR price and quantity levels. Step 4 (Section 2.6) computes the Actual Prices.

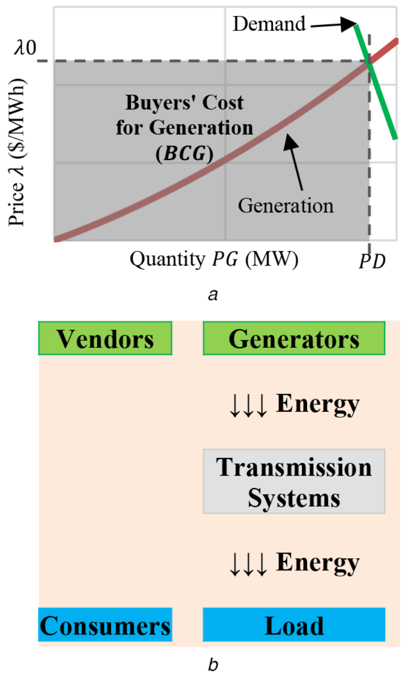

Fig. 3 *Electricity system without demand response*
(a) Electricity settlement graph for a double-ended auction with no DR, ***(b)*** Electricity market structure with no DR

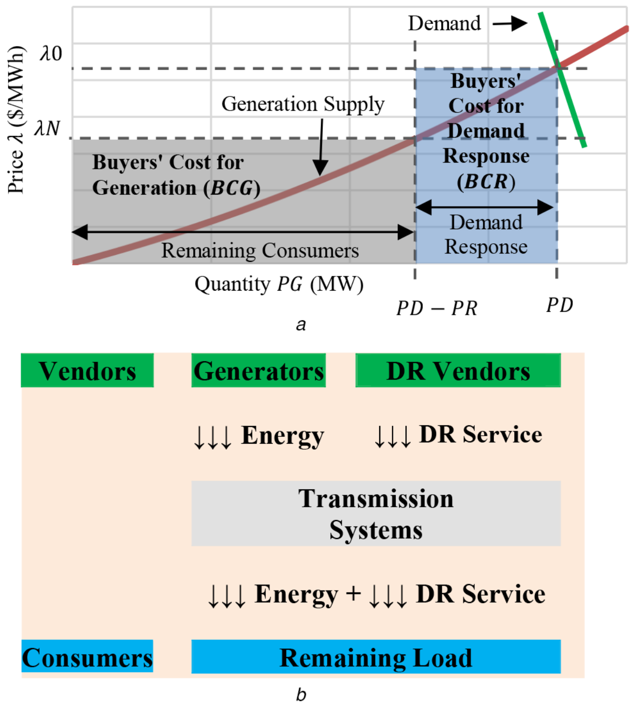

Fig. 4 *Electricity system with demand response*
(a) Electricity settlement graph of a double-ended auction with DR, ***(b)*** Electricity market structure with DR

In addition to the sections outlined above, Section 3 provides the results of applying the proposed DR procurement framework to two real-world systems. The first – the Independent Electricity System Operator (IESO) market in Ontario, Canada – has a single EMCP across the system. The second – PJM – has locational pricing. Section 4 outlines the conclusions of this work.

2 Methodology

In order to facilitate the presentation of the proposed DR procurement process, we will first introduce the new metric of Actual Price, which fully represents the final unit price of electricity paid for by remaining consumers. The four-step process, which is designed to minimise Actual Price, is introduced next.

2.1 Actual price and the FERC NBT

The concept of Actual Price for electricity and its relationship with the FERC NBT is presented below. Consider a generic aggregated generator cost curve $F(PG)$ as a function of the total system generation PG. The aggregate generation price bid curve $\lambda(PG)$ equals

$$\lambda(PG) = \frac{\partial\, F(PG)}{\partial\, PG} \tag{1}$$

In the absence of DR, the total system demand PD is entirely satisfied by generators, and the resulting market-clearing price, $\lambda 0$, can be calculated as below:

$$\lambda 0 = \lambda(PD) \tag{2}$$

Therefore, buyers collectively pay $PD \cdot \lambda 0$ total cost to generators for their supply; this is the Buyers' Cost for Generation (BCG), as shown in Fig. 3.

The economic impact of DR can be shown by considering the double-ended auction, as shown in Fig. 4. With the procurement of quantity PR of DR, several key changes happen simultaneously:

(i) First, a portion of the consumer group of size PR converts from being paying consumers to becoming DR service providers, who are instead paid for their DR service. Therefore, the size of the remaining consumer group that pays becomes PD - PR.
(ii) Second, DR services totalling PR are paid at a rate λPR. In Fig. 4, λPR is shown as $\lambda 0$ for illustrative purposes, but it can be at any level determined by the market designer. In this paper, methods to determine optimal values of λPR will be proposed. The total cost paid to DR service providers BCR is

$$\mathrm{BCR} = \lambda PR \cdot PR \tag{3}$$

(iii) Third, BCG shrinks as less generation are needed to serve the remaining consumers PD - PR. A new market-clearing price of λN is paid to dispatched generators as calculated in (4), and BCG becomes (5)

$$\lambda N(PR) = \lambda(PD - PR) \tag{4}$$

$$\mathrm{BCG} = \lambda N \cdot (PD - PR) \tag{5}$$

(iv) Fourth, the remaining consumers PD - PR must share the total costs, which comprise both generation and DR services. Using only λPR or λN in isolation as a measure of the impact of DR would be incomplete, as those prices represent the rates paid to DR services and to generation, respectively. The Actual Price λA of electricity, as paid by remaining consumers, is the sum of the generation and DR costs shared among the remaining consumers:

$$\lambda A(\lambda PR,\ PR) = \frac{\mathrm{BCG} + \mathrm{BCR}}{PD - PR} \tag{6}$$

Substituting (5) and (3) into (6), $\lambda A(\lambda PR,\ PR)$ becomes

$$\lambda A\ (\lambda PR,\ PR) = \lambda N(PR) + \frac{\lambda PR \cdot PR}{PD - PR} \tag{7}$$

This concept of Actual Price is the most comprehensive and accurate measure of the impact of DR on the remaining consumers. FERC's NBT requires that any procurement of PR at a price of λPR must satisfy the following equation:

$$\lambda A(\lambda PR,\ PR)\ \leq\ [\lambda 0 = \lambda(PD)] \tag{8}$$

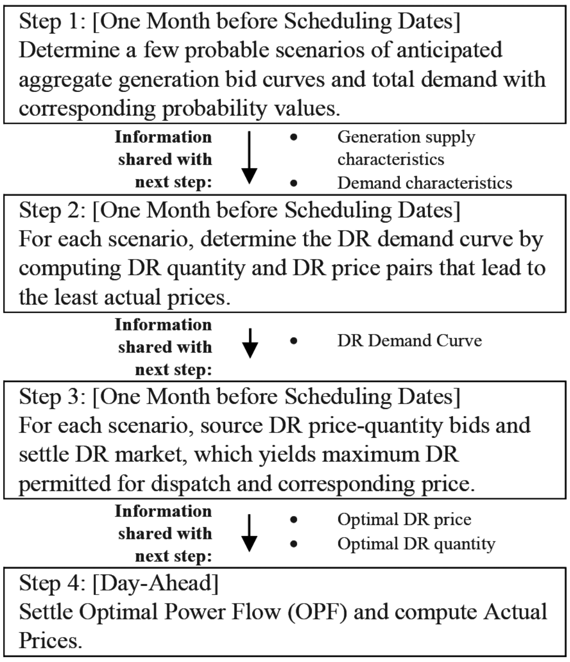

Fig. 5 *Overview of the four-step DR procurement framework*

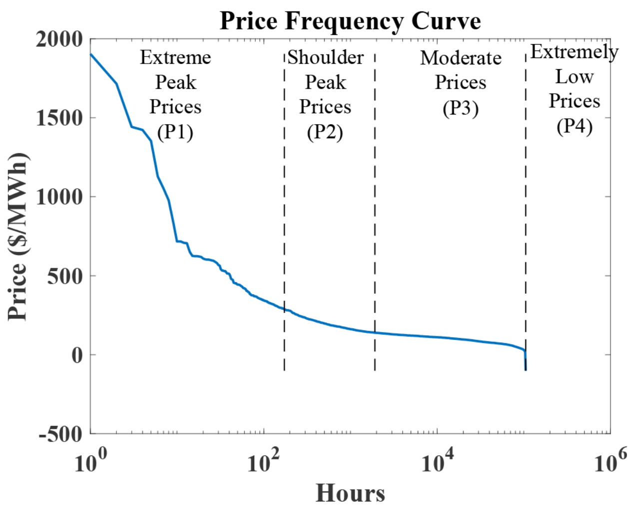

Fig. 6 *IESO electricity price frequency curve, 2005–2016*

2.2 Overview of proposed four-step probabilistic DR procurement process

The consolidated four-step method is shown in Fig. 5. It adapts and expands the existing method in Fig. 1.

2.3 Step 1: develop probabilistic scenarios and aggregate generator supply price curves

To begin, probabilistic scenarios, along with the aggregate generator price bid curves and total system demand associated with each scenario, are needed.

Each probabilistic scenario was categorised to have similar representative price characteristics. Accordingly, considering the example shown in Fig. 6, the first scenario's length was chosen, such that average price characteristics do not deviate from the other points by setting a limit on standard deviation. Once the samples included in a scenario equal the standard deviation limit, the next segment is opened, and samples are included until the standard deviation limit is reached. In systems with higher variability in price, it is possible to improve accuracy by having a lower standard deviation limit and more scenarios. The probability of each scenario was computed to equal the percentage time duration of that scenario as a fraction of the total time duration of all scenarios.

The ideas presented in this paper can be applied to generator price bid curves $\lambda(PG)$ of any form. A common generator supply curve is quadratic, for example in [26], and used to model thermal or hydroelectric unit bids. Its cost curve can be approximated by a third-order polynomial (9) in which PG is total system generation in MW, and a, b, c, and d are constants.

$$F(PG) = a + b \cdot PG + c \cdot PG^2 + d \cdot PG^3 \tag{9}$$

The aggregate generator price bid curve $\lambda(PG)$ is then approximated by differentiating (9) to get (10), as per (1)

$$\lambda(PG) = \frac{\mathrm{d}F(PG)}{\mathrm{d}PG} = b + 2 \cdot c \cdot PG + 3 \cdot d \cdot PG^2 \tag{10}$$

2.4 Step 2: develop a demand curve for DR

Having established in Section 3.1 that λA (Actual Price) is the best metric to assess the impact of DR to the remaining consumers, the optimal outcome for those remaining consumers is the lowest possible λA.

The objective function is

$$\text{Minimise } \lambda A \tag{11}$$

Subject to:

$$0 \le PR \tag{12}$$

$$\lambda A \le \lambda 0 \tag{13}$$

Constraint (12) respects the physical limits of DR, and constraint (13) respects the NBT, as per (8).

λA is minimised by taking its partial derivative with respect to PR and setting it to zero; the optimal quantity of DR (PR) can be determined using (7) and (4)

$$\frac{\partial \lambda A}{\partial PR} = \frac{\partial \lambda(PD - PR)}{\partial PR} + \frac{\lambda PR \cdot PD}{(PD - PR)^2} = 0 \tag{14}$$

Defining a DR demand price function by rearranging (14) and defining the optimal values of PR and λPR as PRD and λPRD, respectively, we can write

$$\lambda \mathrm{PRD}(\mathrm{PRD}) = \left[\frac{-\partial\, \lambda(PD - \mathrm{PRD})}{\partial PR}\right] \cdot \left[\frac{(PD - \mathrm{PRD})^2}{PD}\right] \tag{15}$$

Equation (15) describes the relationship between PRD and λPRD, the price remaining consumers should be willing to pay for DR such that λA is minimised. Hence, for every value of PRD, λPRD determined using (15) describes the optimal value of the payment to DR such that the remaining consumers have the lowest Actual Price λA. This forms the DR demand curve, which shows at each amount of PR, the best price λPR the remaining consumers should pay.

The demand curve for DR is important for market designers to understand the value of DR services to remaining consumers so that actual prices will be kept at a minimum. Paying prices above λPR for DR would be detrimental to λA, while paying prices below λPR would mean that consumers can enjoy a surplus. The demand curve for DR is also necessary for operating and settling the market at the most efficient point.

2.5 Step 3: settle the DR market

With a DR demand curve computed in Step 2, DR offer bids are sought from DR vendors. The supply curve is constructed by stacking the bids from DR service providers from lowest to highest. The optimal settlement point is found by seeking the Nash equilibrium, as shown in Fig. 5, and determined by solving the formulation in (16)–(19).

The objective function is to maximise social welfare in the DR market

$$\text{Maximise} \int_0^{\mathrm{PRD}} \lambda \mathrm{PRD}(\mathrm{PRD}) \cdot PR \cdot d\mathrm{PRD} - \sum_{m=1}^{\mathrm{NDR}} \lambda \mathrm{PRS}_m \cdot \mathrm{PRS}_m \tag{16}$$

The objective function is subject to these constraints:

$$\sum_{m=1}^{\mathrm{NDR}} \mathrm{PRS}_m = \mathrm{PRD} \tag{17}$$

$$0 \le \mathrm{PRS}_m \le \overline{\mathrm{PRS}_m} \tag{18}$$

$$0 \le \mathrm{PRD} \tag{19}$$

This is a non-linear optimisation function, and a classic non-linear optimisation technique can be used to solve it. Constraint (17) ensures DR balance (i.e. that DR supply equals demand), constraint (18) ensures that DR supplier capacity limits are respected, and constraint (19) ensures that DR cannot be negative.

2.6 Step 4: compute actual prices

The final step is to take the optimal quantity of DR from Step 3 ($\overline{PR}$) and use it as an upper constraint of DR procurement in the standard unit commitment. The market is settled with the formulation outlined in (20)–(31). The Actual Price λA can then be determined using (4) and (7). While planning for DR optimal quantity is completed in Step 3, the purpose of Step 4 is to schedule DR and compute actual prices, demonstrating the benefits of the proposed method.

The objective function is to maximise social welfare

$$\text{Maximise} \sum_i^{NB} KD_i \cdot PD_i - \sum_i^{NB} KG_i \cdot PG_i \tag{20}$$

The objective function is subject to these constraints:

(a) Real and reactive power balances

$$PG_i + PR_i - PD_i - V_i \sum_{j=1}^{NB} V_j \cdot Y_{ij} \cdot \cos \delta_i - \delta_j - \theta_{ij} = 0 \quad \forall\, i = 1 \text{ to } NB \tag{21}$$

$$QG_i - QD_i - V_i \sum_{j=1}^{NB} V_j \cdot Y_{ij} \cdot \sin \delta_i - \delta_j - \theta_{ij} = 0 \quad \forall i = 1 \text{ to } NB \tag{22}$$

(b) Voltage limits

$$\underline{V_i} \le V_i \le \overline{V_i} \quad \forall i = 1 \text{ to } NB \tag{23}$$

(c) Line flow limits

$$SF_{ki} = \left[\left(V_i \angle \delta_i - V_j \angle \delta_j\right) \cdot y_{ij} \angle \phi_{ij}\right]^* \cdot V_i \angle \delta_i \quad \forall k = 1 \text{ to } NT; \{i, j\} \in k \tag{24}$$

$$SF_{kj} = \left[\left(V_j \angle \delta_j - V_i \angle \delta_i\right) \cdot y_{ij} \angle \phi_{ij}\right]^* \cdot V_j \angle \delta_j \quad \forall k = 1 \text{ to } NT; \{i, j\} \in k \tag{25}$$

$$|SF_{ki}| \le \overline{SF_k} \quad \forall = 1 \text{ to } NT; \{i, j\} \in k \tag{26}$$

$$\left|SF_{kj}\right| \le \overline{SF_k} \quad \forall = 1 \text{ to } NT; \{i, j\} \in k \tag{27}$$

(d) Real and reactive generator limits

$$\underline{PG_i} \le PG_i \le \overline{PG_i} \quad \forall\, i = 1 \text{ to } NB \tag{28}$$

$$\underline{QG_i} \le QG_i \le \overline{QG_i} \quad \forall i = 1 \text{ to } NB \tag{29}$$

(e) DR limits, using $\overline{PR}$ determined in Step 3

$$\sum_i^{NB} PR_i \le \overline{PR} \tag{30}$$

$$0 \le PR_i \le \overline{PR_i} \quad \forall i = 1 \text{ to } NB \tag{31}$$

This is a non-linear optimisation problem and can be solved with classic non-linear optimisation techniques. In order to clearly explain the new ideas, this simplified formulation, with an unconstrained network, is used.

Once the formulation is solved and the value of the nodal price λN is determined, the Actual Price λA can be computed using (7).

2.7 Inefficiencies of procuring sub-optimal quantities of DR

Operators need to know the expected quantity and price for DR procurement. The expected DR quantity, PR_{EXP}, is the weighted average of DR quantity in each of the time periods, as shown in (32). The total costs are the prices multiplied by quantities, weighted by duration, as shown in (33). The average annual actual price is the total costs in (33) divided by the total quantities, as shown in (34)

$$PR_{\mathrm{EXP}} = \sum_{h=1}^{NH} p_h \cdot \overline{PR_h} \tag{32}$$

$$\text{Total Costs} = \sum_{h=1}^{NH} \lambda A_h \cdot \left(PD_h - \overline{PR_h}\right) \cdot T_h \tag{33}$$

$$\text{Average } \lambda A = \frac{\sum_{h=1}^{NH} \lambda A_h \cdot \left(PD_h - \overline{PR_h}\right) \cdot T_h}{\sum_{h=1}^{NH} \left(PD_h - \overline{PR_h}\right) \cdot T_h} \tag{34}$$

Operators should procure PR_{EXP} if they are to use a single optimal quantity for the entire period.

2.8 Systems with varied locational pricing

The process outlined so far will work in a system that is not network constrained and in which Locational Marginal Price (LMP) is nearly the same at every node, like in Ontario. In network constrained power systems with significantly different nodal LMPs, the actual node-specific LMPs would be needed instead. Location-specific pricing can be modelled by dividing the power system into a set of internally uncongested zones each with nearly the same LMP at all nodes within them and then applying the proposed process within each zone. We will demonstrate this method in the second case study for PJM in the next section.

3 Results: probabilistic-based DR procurement

To demonstrate the application of the proposed methodology, we conducted two case studies based on actual system data. The first case study is for the Independent Electricity System Operator (IESO) in Ontario, Canada. The IESO has one system-wide price for electricity. The second case study is for PJM Interconnection, whose jurisdiction spans multiple states in the North-Eastern United States. Since PJM uses locational pricing, we also analyse a congested zone separately.

3.1 Case study 1: IESO in Ontario, Canada

3.1.1 Step 1: Four representative scenarios representing possible generator bid and total load are analysed. Consider historical hourly energy prices in Ontario's power system from 2005 to 2016, a period of 12 years [27]. The prices are the sum of the Hourly Ontario Energy Price and the Global Adjustment Charge. All other

Table 1 Historical system characteristics for IESO

	Units	Extreme peak prices (P1)	Shoulder peak prices (P2)	Moderate prices (P3)	Extreme low prices (P4)
median price in region $\lambda 0$	\$/MWh	360.45	160.41	70.28	−0.46
median quantity in region *PD*	MW	22,371	20,171	17,073	13,741
% of duration	%	0.16	1.66	97.81	0.37
hours/year	h	14.0	145.4	8568.2	32.4
generation supply bid curve characteristic	*a* \$	1	1	1	1
	b \$/MWh	10	10	10	−20
	c \$/MWh^2	-3.50×10^{-7}	-1.85×10^{-7}	-1.03×10^{-7}	-5.17×10^{-8}
	d \$/MWh^3	2.33×10^{-7}	1.23×10^{-7}	6.89×10^{-8}	3.45×10^{-8}

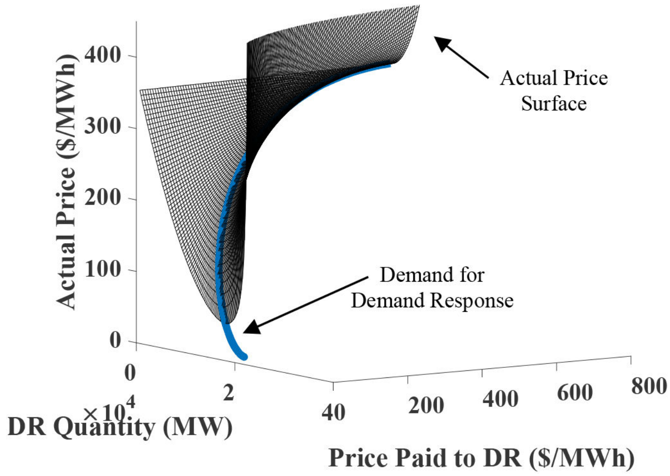

Fig. 7 *Actual price surface as a function of DR quantity and price paid to DR for period P1*

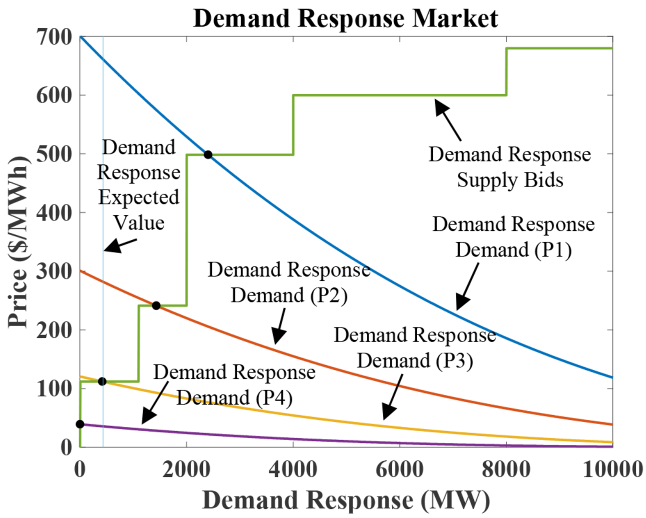

Fig. 8 *DR supply and demand curves for IESO's historical system*

charges, including delivery, regulatory, and taxes, were not considered for this analysis.

Re-ordering the electricity prices from largest to smallest yields the price frequency curve, as shown logarithmically in Fig. 6. This curve was then divided into four representative scenarios by price: extreme peak prices (P1); shoulder peak prices (P2); moderate prices (P3); and extremely low prices (P4). The median price point in each of these regions was used to embody each region in the analysis, and details are in Table 1. For simplicity, it is assumed that the historical price and quantity data does not include DR. The probability of occurrence of each scenario P1 to P4 is proportional to their corresponding duration. For example, scenario P1 has a probability of 0.0016. The generator bid supply curve characteristics for each period in Table 1 are for the curve in the form (10).

The variation of the Actual Price is shown in Fig. 7 for period P1 of IESO's historical data from Table 1. Intuitively, it is evident that a set of $\{\lambda PR, PR\}$ pairs, as shown by the blue curve, will yield the least λA values. This is used to construct the demand curve for DR in step 2 of the proposed algorithm.

3.1.2 Step 2: Using (10) and (15), we determine the DR demand curve when the generator price bid curve is quadratic

$$\lambda \mathrm{PRD}(PR) = \frac{6 \cdot d}{PD}\left[(PD - PR)^3 + \frac{c}{3 \cdot d}(PD - PR)^2\right] \qquad (35)$$

DR demand curves were created based on (35) for periods P1, P2, and P3 in Table 1 and shown in Fig. 8. P4 was excluded because it had a negative price and hence, no need for DR. (The DR supply

Table 2 DR supply bids

Supply bid	1	2	3	4	5
price λPR, \$/MWh	111.95	241.22	498.37	600	680
quantity PR, MW	1100	900	2000	4000	2000

Table 3 Optimal DR price and quantities

Time period	P1	P2	P3	P4
probability of occurrence, %	0.16	1.66	97.81	0.37
$\overline{\lambda PR}$, \$/MWh	498.37	241.22	111.95	39.08
$\overline{PR}$, MW	2404	1431	417	0

Table 4 Actual prices for IESO's historical electricity system under optimal DR procurement conditions

	Units	P1	P2	P3	P4
minimum λA	\$/MWh	**349.18**	**158.24**	**70.17**	**−0.46**
median price in region $\lambda 0$	\$/MWh	360.45	160.41	70.28	−0.46
price paid to generators λN	\$/MWh	289.18	139.82	67.38	−0.46

The bolded numbers show the optimal results and convey the value of our proposed method.

Table 5 Expected values of DR and Expected Savings for consumers at the optimal condition for IESO's electricity system

	Units	Extreme peak prices (P1)	Shoulder peak prices (P2)	Moderate prices (P3)	Extreme low prices (P4)	Annual
expected DR purchased/year	GWh	33	208	3568	0	3809
expected savings for remaining consumers/year	\$1000	3154	5898	15,099	0	24,151

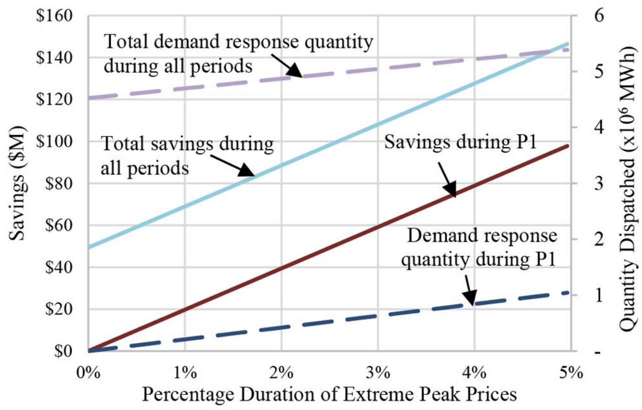

Fig. 9 *Expected annual collective savings for remaining consumers due to DR and expected quantities of DR dispatched under various percentages of the duration of extreme peak prices, i.e. the duration of P1*

bids and expected value of DR in Fig. 8 will be explained later in this paper.)

3.1.3 Step 3: Continuing with IESO's probabilistic scenarios in Table 1, P1, P2, and P3 were settled with the optimisation formulation in (16)–(19) and the five sample DR supply bids in Table 2. (For simplicity, the same DR supply bids were used for all scenarios.)

Optimal DR market settlement results of the four scenarios are shown in Table 3 and Fig. 8.

3.1.4 Significance of DR market settlement periods (multiple markets – periods): Implementing this DR market scheme for short-term DR procurement requires settling the market for each of the representative scenarios in advance. As can be seen in Table 3, scenario P3 has a probability of occurrence of 97.81% and commands a lower settlement price, whereas scenario P1 has a probability of 0.16% and commands a much higher price of \$498.37. A separate DR auction is required for each scenario because the demand bids will be different for each scenario. Therefore, the optimum settlement points will differ as well.

3.1.5 Step 4: After executing steps 1–3, the Actual Prices for each period can be calculated. The results are shown in Table 4. Also included are the new EMCPs (λN) paid to generators.

3.1.6 Summary of results for IESO case: Table 5 shows each of the four periods under optimal procurement of DR. Values were calculated using the methods proposed in Section 3.7. The optimal quantity of DR and corresponding savings were weighted with the percentage duration of that period.

Table 5 shows that IESO consumers could have collectively saved over \$24 million annually through optimal procurement of DR in 2005–2016 inclusive for the example DR supply bid described in Table 2. The extreme peak price period (P1) occurs for the shortest amount of time – about 14 h per year – and can represent extreme weather events. The highest optimal prices and quantities for DR occur in P1 as that is when there is the greatest need for DR. However, the greatest collective savings are found in the moderate price period (P3) because most of the time – 97.81% – is in this category. Since the median starting price for P4 is already negative, no DR is necessary to further lower the price.

While the use of assumed values for DR supply introduces uncertainty around the absolute values of the results, the relative performance of DR in each of the four periods still holds. Historical consumption data was used in this example, but DR supply price data was unavailable. Actual DR supply data can be incorporated as it becomes known in the future.

It is evident that DR, when procured optimally, has the potential to deliver savings to consumers during the better part of the year.

3.1.7 Sensitivity analysis – duration of extreme prices: Should extreme weather events occur more frequently in the future due to climate change, the duration of P1 and P2 are expected to increase, while P3 and P4 are expected to decrease. As the percentage duration of extreme peak prices increases, both the total quantity of DR purchased per year and the total savings due to DR for the remaining consumers per year increase. Fig. 9 illustrates these patterns as the duration of P1 increases from 0 to 5% per year.

This shows that DR will become an increasingly powerful tool for ISOs to moderate Actual Prices as periods of extreme peak prices grow longer in duration. This can be due to events that are

Table 6 Effects of sub-optimal DR procurement

DR quantity	DR quantity procured per hour, MW	Total costs, $B	Inefficiency, %	Average actual price λA, $/MWh
PR_1	2404	17.75	68.08	137.69
PR_2	1431	11.62	10.01	84.53
PR_3	417	10.57	0.12	72.26
PR_4	0	10.86	2.87	72.44
PR_{EXP}	435	10.56	**0**	**72.25**

The bolded numbers show the optimal results and convey the value of our proposed method.

Table 7 Comparison between the proposed method and published methods [17]

	Units	Extreme peak prices (P1)	Shoulder peak prices (P2)	Moderate prices (P3)	Extreme low prices (P4)
Published methods [17]					
DR purchased	MW	435	435	0	—
actual price λA	$/MWh	353.84	157.38	70.28	—
net payment	$1000	$7762	$3106	$1200	—
Method proposed in this paper					
DR purchased	MW	435	435	435	—
actual price λA	$/MWh	349.18	156.46	70.17	—
net payment	$1000	$7660	$3088	$1168	—
benefit from the proposed method	$1000	$102	$18	$32	—

difficult to plan for, such as extreme weather events or natural gas supply disruptions.

3.1.8 Inefficiencies of procuring sub-optimal quantities of DR: Operators should procure PR_{EXP} if they are to use a single optimal quantity for the entire period.

Table 6 shows the key measures if a single amount of DR is procured for the entire period. The quantities compared are the optimal quantities from each of the four time periods PR_1 to PR_4 and the expected value PR_{EXP}. The total costs and average actual prices are found using (33) and (34), respectively. The inefficiency is the difference in total costs relative to the optimal case of purchasing PR_{EXP} for the entire period.

It is clear from the comparison that procuring PR_{EXP} would deliver optimal outcomes for consumers. Procuring other quantity levels would be sub-optimal.

Hence, the method proposed in this paper recommends procurement of 435 MW of DR and it would result in the lowest Actual Price for the IESO operated power system.

3.1.9 Comparison with existing DR procurement methods: We compared our results with the existing practice of paying DR the EMCP, which appears in the literature [17]. The comparison is in Table 7. For planning purposes, we procure the expected DR quantity, PR_{EXP}, of 435 MW, as shown in Table 6. It is evident that our proposed method yields lower actual prices in all time periods when compared to existing methods used in the literature. Note that in the third period (P3), no DR can be procured through existing published methods because the EMCP without DR ($\lambda 0$) is 70.28, which is too low to buy any of the DR supply offered, as shown in Table 2.

In addition, benefit from the proposed method for the remaining customers can be quantified as $281 million annually, which is the benefit shown in Table 7 applied to the hours for that scenario per year, as shown in Table 1. This amount is left behind in the electricity market when DR is forced to pay at the EMCP rates, which is not economical for their service model, and hence they opt out by not participating in the electricity market.

This result resoundingly reinforces the fact that DR service vendors have an economic model, which dictates that they should offer their own prices. These offer prices, when considered in Step 3 of the proposed DR market clearing process, set the stage for their procurement. When these competitively procured DR services are scheduled, not only are the Actual Prices lower, the customers save a significant amount, and electricity markets are driven towards efficient operations.

3.2 Case study 2: PJM interconnection in the North-Eastern United States

Actual data for demand [28] and price [29] for PJM Interconnection for 2014 were used. We analysed two areas: system-wide PJM and the zone served by PEPCO in Washington, DC, and the surrounding parts of Maryland. During peak loading times in 2014, customers in the PEPCO zone paid higher electricity prices than the rest of the system due to congestion. These results will show the importance of analysing constrained zones separately rather than grouping them in with system-wide analysis.

3.2.1 Step 1: The price frequency curves showing the sorted EMCP for both the PEPCO zone and the PJM system in 2014 are captured in Fig. 10. The data is divided into four representative time periods as before: extreme peak prices (P1); shoulder peak prices (P2); moderate prices (P3); and extremely low prices (P4). The characteristics for each time period are in Table 8 for the PJM-wide system and Table 9 for the PEPCO zone.

3.2.2 Step 2: The demand curves for DR were calculated using the data above and shown in Fig. 11 for PJM and Fig. 12 for PEPCO.

3.2.3 Step 3: On the supply side of DR, sample bids were used for both the PJM system (Table 10) and for PEPCO (Table 11).

The DR market is settled, as shown in Fig. 11 for PJM and Fig. 12 for PEPCO. We obtain the results for PJM (Table 12) and PEPCO (Table 13).

3.2.4 Step 4: Actual prices were computed, as shown in Table 14 for PJM and Table 15 for PEPCO. In all cases, in which DR is purchased (i.e. in time periods P1 and P2), we can see that *the purchase of DR lowers the prices paid by remaining consumers*, demonstrating the efficacy and benefits of our proposed methodology. During extreme peak periods (P1), electricity prices are lowered by 0.64 and 9.48% for PJM and PEPCO, respectively. Furthermore, we prove that our proposed methodology is functional and effective for jurisdictions using locational pricing.

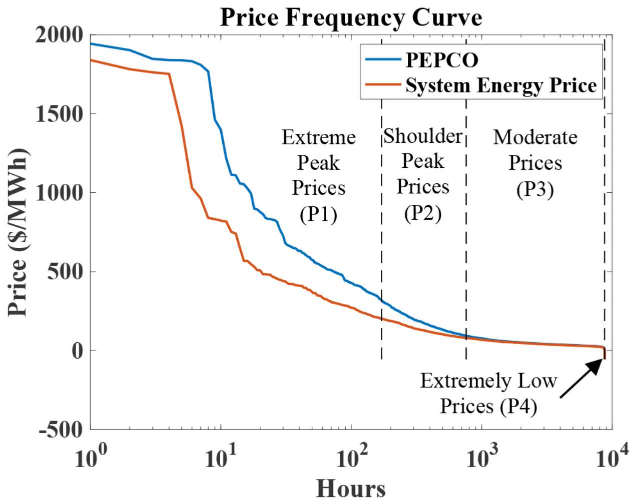

Fig. 10 *PJM electricity price frequency curve, 2014*

Table 8 System characteristics for PJM in 2014

		Units	Extreme peak prices (P1)	Shoulder peak prices (P2)	Moderate prices (P3)	Extreme low prices (P4)
median price in region $\lambda 0$		\$/MWh	288.96	107.59	33.27	0
median quantity in region *PD*		MW	5168	3105	3295	2570
% of duration		%	1.94	6.71	91.00	0.33
hours/year		h	170	588	7972	29
generation supply bid curve characteristic	*a*	\$	1	1	1	1
	b	\$/MWh	1	1	1	−20
	c	\$/MWh^2	-1.02×10^{-8}	1.23×10^{-14}	-1.47×10^{-9}	-2.70×10^{-9}
	d	\$/MWh^3	6.78×10^{-9}	2.29×10^{-9}	9.77×10^{-10}	1.80×10^{-9}

Table 9 Characteristics for PEPCO zone in PJM in 2014

		Units	Extreme peak prices (P1)	Shoulder peak prices (P2)	Moderate prices (P3)	Extreme low prices (P4)
median price in region $\lambda 0$		\$/MWh	470.64	140.91	35.18	0
median quantity in region *PD*		MW	119,004	124,478	104,933	60,890
% of duration		%	1.94	6.71	91.00	0.33
hours/year		h	170	588	7972	29
generation supply bid curve characteristic	*a*	\$	1	1	1	1
	b	\$/MWh	1	1	1	−20
	c	\$/MWh^2	-8.79×10^{-6}	-7.26×10^{-6}	-1.57×10^{-6}	-1.52×10^{-6}
	d	\$/MWh^3	5.86×10^{-6}	4.84×10^{-6}	1.05×10^{-6}	1.01×10^{-6}

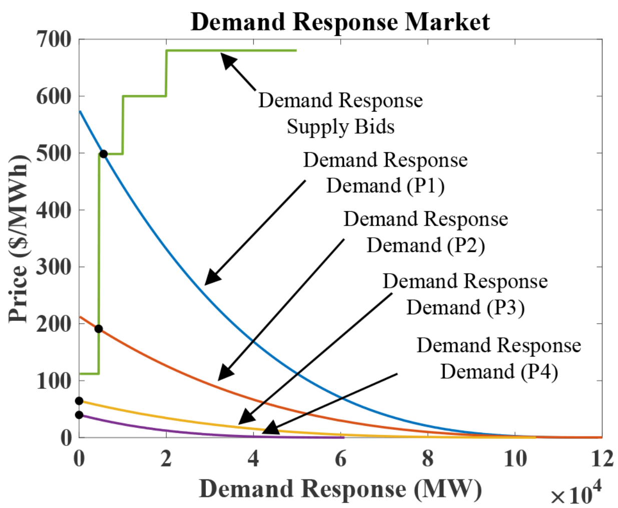

Fig. 11 *DR supply and demand curves for PJM, 2014*

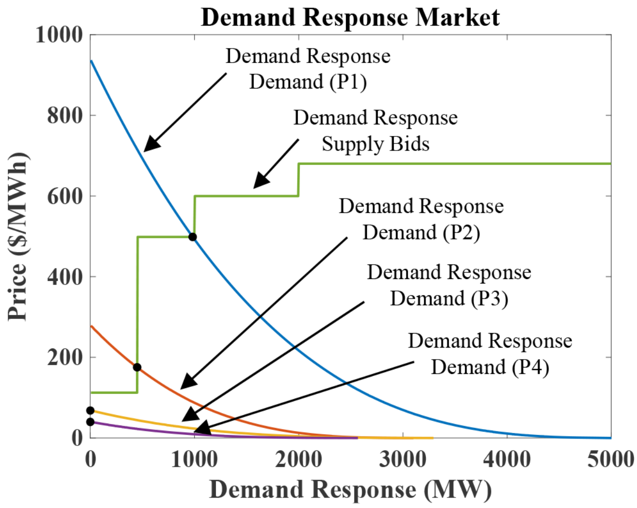

Fig. 12 *DR supply and demand curves for PEPCO zone in PJM, 2014*

Table 10 DR supply bids in PJM

Supply bid	1	2	3	4	5
price λPR, $/MWh	111.95	241.22	498.37	600	680
quantity *PR*, MW	5500	4500	10,000	20,000	10,000

Table 11 DR supply bids in PEPCO zone in PJM

Supply bid	1	2	3	4	5
price λPR, $/MWh	111.95	241.22	498.37	600	680
quantity *PR*, MW	550	450	1000	2000	1000

Table 12 Optimal DR price and quantities in PJM

Time period	P1	P2	P3	P4
probability of occurrence, %	1.94	6.71	91.00	0.37
$\overline{\lambda PR}$, $/MWh	498.37	190.97	64.31	39.76
$\overline{PR}$, MW	5601	4481	—	—

Table 13 Optimal DR price and quantities in PEPCO

Time period	P1	P2	P3	P4
probability of occurrence, %	1.94	6.71	91.00	0.37
$\overline{\lambda PR}$, $/MWh	498.37	175.02	68.05	39.77
$\overline{PR}$, MW	982	450	—	—

Table 14 Actual prices for PJM's historical electricity system under optimal DR procurement conditions

	Units	P1	P2	P3	P4
minimum λA	$/MWh	**287.10**	**107.18**	33.27	0.00
median price in region $\lambda 0$	$/MWh	288.96	107.59	33.27	0.00
price paid to generators λN	$/MWh	262.49	100.05	33.27	0.00

The bolded numbers show the optimal results and convey the value of our proposed method.

Table 15 Actual prices for PEPCO's historical electricity system under optimal DR procurement conditions

	Units	P1	P2	P3	P4
minimum λA	$/MWh	**426.02**	**132.95**	35.18	0.00
median price in region $\lambda 0$	$/MWh	470.64	140.91	35.18	0.00
price paid to generators λN	$/MWh	309.11	103.31	35.18	0.00

The bolded numbers show the optimal results and convey the value of our proposed method.

3.2.5 Summary: This case study for PJM and PEPCO areas shows our methodology applied to a system with location pricing. Our proposed DR procurement will lower the electricity price for remaining consumers by 0.64% in PJM and 9.48% in PEPCO. It is expected to collectively save the remaining consumers $64 million annually in PJM and $44 million in PEPCO, as shown in Tables 16 and 17 for PJM and PEPCO, respectively.

3.2.6 Comparison with existing DR procurement methods: We compared our results with the existing practice in

Table 16 Expected values of DR purchase and savings for customers at optimal conditions for PJM's electricity system

	Units	Extreme peak prices (P1)	Shoulder peak prices (P2)	Moderate prices (P3)	Extreme low prices (P4)	Annual
expected DR purchased/year	GWh	952	2635	—	—	3587
expected savings for remaining consumers/year	$1000	35,729	28,538	—	—	64,267

Table 17 Expected values of optimal conditions for PEPCO's historical electricity system

	Units	Extreme peak prices (P1)	Shoulder peak prices (P2)	Moderate prices (P3)	Extreme low prices (P4)	Annual
expected DR purchased/year	GWh	167	264	—	—	431
expected savings for remaining consumers/year	$1000	31,754	12,419	—	—	44,174

Table 18 Comparison between proposed method and published methods for PJM [17]

	Units	Extreme peak prices (P1)	Shoulder peak prices (P2)	Moderate prices (P3)	Extreme low prices (P4)
Published methods [17]					
DR purchased	MW	409	—	—	—
actual price λA	$/MWh	287.97	107.59	33.27	—
net payment	$1000	34,152	13,392	3491	—
Method proposed in this paper					
DR purchased	MW	409	409	—	—
actual price λA	$/MWh	287.37	107.26	33.27	—
net payment	$1000	34,080	13,307	3491	—
—	—	—	—	—	—
benefit from the proposed method	$1000	72	85	—	—

Table 19 Comparison between the proposed method and published methods for PEPCO [17]

	Units	Extreme peak prices (P1)	Shoulder peak prices (P2)	Moderate prices (P3)	Extreme low prices (P4)
Published methods [17]					
DR purchased	MW	49	49	—	—
actual price λA	$/MWh	466.19	138.71	35.18	—
net payment	$1000	2387	424	116	—
Method proposed in this paper					
DR purchased	MW	49	49	—	—
actual price λA	$/MWh	462.84	138.32	35.18	—
net payment	$1000	2369	423	116	—
—	—	—	—	—	—
benefit from the proposed method	$1000	17	1	—	—

the literature of paying DR the EMCP [17]. The comparisons are in Table 18 for PJM and Table 19 for PEPCO. For planning purposes, we procure the expected DR quantity, PR_{EXP}, of 409 MW for PJM and 49 MW for PEPCO, as determined using (32). It is evident that our proposed method yields lower actual prices in all time periods when compared to existing methods used in the literature.

In addition, benefit from the proposed method for the remaining customers can be quantified as $62.1 million and $3.6 million annually for PJM and PEPCO respectively, which is the benefit shown in Table 18 for PJM and Table 19 for PEPCO applied to the hours for that scenario per year, as shown in Table 8 for PJM and Table 9 for PEPCO. This amount is left behind in the electricity market when DR is forced to pay at the EMCP rates, which is not economical for their service model, and hence they opt out by not participating in the electricity market.

This result again resoundingly reinforces the fact that DR service vendors have an economic model, which dictates their own offer prices. These offer prices, when considered in Step 3 of the proposed DR market clearing processes, set the stage for their procurement. When these competitively procured DR services are scheduled, not only the Actual Prices are lower, the customers gain a significant amount of savings, and electricity markets are driven towards efficient operations.

4 Conclusions

The main goal of this paper is to determine a fair and just price for DR that will ensure that social welfare is maximised for an entire market, comprising consumers, DR suppliers, and generators. The current practice is to pay DR at EMCP, which is determined by generators and consumers only. The lack of DR supplier information results in sub-optimal outcomes for the market.

In this paper, we offer three main contributions:

(i) a market-based price for DR;
(ii) a new performance metric, Actual Price, which accounts for payments to DR suppliers and the reduced pool of paying consumers when DR is procured; and
(iii) a four-step probabilistic DR procurement framework to optimally purchase DR.

Our market-based method for setting prices for DR and enabling DR participation in an optimal dispatch model yields lower Actual Prices for consumers when compared to existing DR procurement methods found in the literature.

We applied this framework to historical data from the IESO and PJM electricity systems to show that our method will yield optimal outcomes for consumers. Our method calculates the expected quantities and prices of DR to procure in order to maximise social welfare in the DR market and minimise λA for remaining consumers. In the IESO example, our method yields $24 million in annual savings, while in the PJM case, consumers could save $64 million. We also show that our method outperforms existing procurement methods in the literature by integrating the supply bids from DR vendors in our framework.

While the primary beneficiaries of our proposed framework are electricity consumers through minimum λA, other entities also gain. First, FERC and equivalent international regulatory bodies can use this research as a scientific basis to inform policy decisions of appropriate and optimal prices to pay for DR. This requires both the demand and supply curves for the DR market. Existing practice does not account for either, so a DR market might not materialise because the DR market price is artificially suppressed by the policy choice of paying DR at EMCP. Second, ISOs are given tools to optimally procure DR and generation simultaneously. Traditional market settlement methods, which are designed for a single commodity, are insufficient to handle this complex scenario. ISOs also gain objective, analytical methods to design their cumulative DR procurement programs, whether through energy, capacity, or other markets. Third, system planners are equipped with a method to plan that increasingly includes non-traditional resources such as DR.

While this work is focused on the market-driven DR planning issue, future work could entail the scheduling side of this challenge.

5 Acknowledgments

Financial support from the Independent Electricity System Operator is gratefully acknowledged. Any opinions, findings, conclusions or recommendations are those of the authors and do not reflect the views of the Independent Electricity System Operator, its employees or its administration. Additional financial support from the Natural Sciences and Engineering Research Council of Canada (NSERC) is gratefully acknowledged.

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