# Dynamic Pricing for Responsive Demand to Increase Distribution Network Efficiency

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***Abstract***—This paper designs a novel dynamic tariff scheme for demand response by considering networks costs through balancing the trade-off between network investment costs and operation costs. The target is to actively engage customers into network planning and operation for reducing network costs and finally their electricity bills. System operation costs are quantified according to generation or load curtailment by assessing their contribution to network congestion. Plus, network investment cost is quantified through examining the needed investment for resolving system congestion. Customers located at various might be facing the same energy signals but they are differentiated by network cost signals. Once customers conduct demand response during system congestion periods, the smaller savings from investment and operation cost are considered as economic singles for rewarding the response. The innovation is that it translates network operation/investment costs into tariffs, where current research is mainly focused on linking customer response to energy prices. Typical UK distribution networks are utilised to illustrate the new approach and results show that the economic signals can effectively benefit end customers for reducing system operation costs and deferring needed network investment.

***Keywords —*** Network congestion, investment, demand response, tariff, load curtailment, generation curtailment.

## 1. Introduction

In the new energy landscape with increasing renewable energy penetration, regulators require network operators to justify their investments in order to reduce the cost of decarbonisation. The aim is not only to maximise social resources but also safeguard the benefits of vulnerable end customers. For example, the new regulatory framework in the UK for distribution network operators-RIIO by the Office of Gas and Electricity Markets (Ofgem) has placed a strong emphasis on developing innovative and efficient network solutions, where demand response will be a key player [1]. Thus, network investment might not be the most economic option for operators to ensure sufficient network available capacity. Enabled by smart metering, customers can change their electricity usage in response to the conditions of networks and generation. In the UK alone, 53million smart meters will roll out by 2020 to all homes and small businesses [2].

Normally, demand response can be achieved through sending economic signals to customers, which comes in the form of pricing. By far, there is a large volume of research on dynamic pricing schemes, but most of them aim at energy costs that customer confront [3, 4]. Research in tariff design very much focuses on transforming flat-rate into time-of-use tariffs so that tariffs have variations over time to enable end customer response [5]. Some efforts have been dedicated to designing dynamic pricing which can reflect the energy cost variation at the wholesale market. Work [6]in falls into this category.

The stochastic techniques quadratic programming are used to setting the pricing signal for price elasticities of demand in Paper [7]. It considers the practical aspects such as economic efficiency promotion, revenue adequacy assurance and incentives provision to maximize total economic welfare. However, the economic signal cannot reflect the network condition to the customers. Paper [8] focuses on the balancing between demand side operation and investment activities to maximize the profits which cover both operation and investment based on Short Run Marginal Cost pricing. The forecast of pricing structures is needed to combine the investment and operation activities. Paper [9] proposes cost reflective pricing signals to LV grid users by quantifying their degree of cross-subsidisation.

On the other hand, network costs also account for a large proportion of end customer bills. In the UK, the network costs, in terms of Use-of-System charges take up around 25% of customer bills. This justifies that dynamic tariffs to customers should reflect not only energy costs but also network operation and investment costs. In this way, the economic signals can incentive customers to avoid using electricity n during network peak or congested periods so that required network investments can be delayed or avoided. Further, in order to manage network stress, it is important that when large flexible loads are connected to networks, such as EVs, heat pumps, etc. networks are notified, but currently these loads are notified to DNOs in an inconsistent or inaccurate manner. This creates great challenges to DNOs as the condition of their networks are only partially invisible to them. Therefore, it is essential that DNOs have some type of instruments they can use to control/influence the invisible technologies.

Dynamic pricing is one of the effective economic tools [10]. There are several papers focusing on dynamic pricing design combined with other methods such as energy management, to generate economic signals to influence flexible loads and malicious users. Papers [11, 12] consider dynamic pricing for energy management. The degree of flexibility is offered in pricing operations by focusing on dynamic tariffs, which are derived based on the actual costs from the power market. Paper [13] uses dynamic pricing to address the centralised demand response. It augments dynamic pricing with measure design to avoid demand response centralising caused by the combination of consumer's response to dynamic pricing. Paper [14] uses reinforcement learning algorithms to analyse the dynamic pricing and energy consumption issues between customers and utility companies in a microgrid. A new dynamic pricing is designed for demand response which can ensure cost savings for flexible loads in distribution networks in [15]. Paper [16] uses a dynamic pricing algorithm for the unstable energy use and malicious users in smart grids. The real-time dynamic pricing for malicious users and unstable energy providers helps to flatten load profiles. The impact of dynamic pricing to peak demand, supplier profits, energy bills and congestion costs are analysed in paper [17].

To summarise, most previous work is focused on designing price signals based energy prices, i.e. the relation between suppliers/retailers and customers, but limited attention has been devoted to designing cost-reflective pricing schemes used by network operators that reflect for network costs. Paper [18] quantifies the impact of demand response on network investment costs, but they do not design tariff schemes to reflect the costs in end customers' bills. It is important to relate investment cost to operation cost, but paper [19] does not convert the costs into economic signals.

In order to fill the research gap, this paper designs dynamic tariffs considering network costs, which primarily are distribution network costs. Thus customers, who response to networks conditions, can benefit from operation and investment cost reduction. This paper first fights the balance between network investment costs and operation costs. System operation costs are quantified according to generation or load curtailment by assessing their contribution to network congestion. Network investment cost is quantified for resolving system congestion. A power transfer distribution factor (PTDF) is utilised to assess nodal power impact on branch flows, which then translates into a change of reinforcement horizons. Once customers' conduct demand response during system peak periods, the smaller savings from investment and operation cost are considered as economic singles for rewarding the response. This approach determines not only the magnitude of operation and investment costs but also their occurrence times, so that they can be easily translated into time-varying signals.

The main contribution is that this paper: i) relates system operation costs to investment costs which vary at very different time granularity; ii) introduces a dynamic pricing scheme to reflect customer response on the two costs; iii) translates customer impact on networks into economic signals.

The rest of this paper is organised as: Section II discussed network operation cost v.s. investment cost. In Section III, the two costs are quantified. Section IV proposed the new network pricing scheme and Section V illustrates the scheme on the typical distribution network. Section VIII concludes this paper.

## 2. Network Investment Cost and Operation Cost

Network investment and operation are two options that DNOs can choose to manage their networks to accommodate generation and demand. Network congestion is caused by limited network capacity to transfer electricity.

- Operation cost: Generation of DGs or demand needs to be curtailed in order to alleviate congestion in order to save network investment. Thus the operation cost is quantified as the cost to curtail generation and demand.
- Investment cost: By contrast, investment can be conducted to remove congestions, and the investment cost is the total asset cost plus labor cost and installation costs. Investment cost is annuitized over the lifetime of an asset.

From an economic aspect, there should be an equilibrium between network investment cost and operation cost. If it is highly likely that operation cost in the following years will increase over that in the current year. Thus, once annual total operation cost is larger than annual investment cost, it is more economical to reinforce the networks, otherwise to conduct network operation.

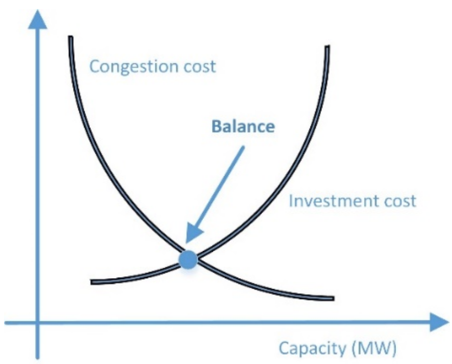


Fig. 1. Trade-off between investment and operation costs

Under this new environment, the relationship between customers and networks becomes more flexible. During peak demand periods, demand shifting/reduction bring benefits in terms of investment deferral. Demand shifting/reduction can also reduce operation costs if it can shift consumption away from system congested periods. The challenge in finding the balance between the two costs is that operation cost is short-term, normally within hours but investment cost is long-term and varies at year scale.

## 3. Quantification of Operation and Investment Cost

This section quantifies network operation and investment costs related to demand response. The savings in the two costs are deducted from the end customer original bills as benefits for their response. The impact of nodal demand/generation change on branch flow is quantified by the Power Transfer Distribution Factor (PTDF) matrix.

### 3.1 Impact of Nodal Power on Branch Flow

There are many ways to quantify the impact of demand and generation change on a particular component. In this paper, power transfer distribution factor (PTDF) power transfer distribution factor is used for its simplicity [20]. PTDF is a sensitivity matrix of line active power flow with respect to nodal power injection. When an overloading is detected in the system, the most heavily overloaded line m is found first. PTDF is introduced to select the most sensitive busbar, which has the largest impact on line m. Therefore, generation or demand at that busbar can be curtailed to resolve the overloading. Accordingly, load curtailment ΔDgi or generation curtailment ΔPgi to resolve the overloading is

$$P_{gi} = \min \left\{ \frac{|P_m - P_m^{max}|}{PTDF(m,gi) - PTDF(m,si)}, P_{gi} \right\}, i \in NG \tag{1}$$

where *si* is the slack bus, $P_m$ is the power flow on line *m*, and $P_m^{max}$ is rated capacity of line *m*.

### 3.2 Network Operation Cost

Based on time-series system analysis, the occurrence time, location, and amount of congestion can be determined properly. Load or generation curtailment is implemented according to the impact of their change on branch flows. The cost to curtail load is decided by the curtailing amount, time, duration, and the unit value of electricity. Here, the unit demand curtailment cost is chosen as Value of Lost Load (VoLL). Thus, the annual load curtailment cost is

$$DCurtail_h = \sum_{k=1}^{365} \sum_{j=1}^{24} \sum_{i=1}^{T} D_{i,j,k} \cdot VoLL_{i,i,k} \tag{2}$$

where *k* is day index, j is hour index, i is load index, Di is the curtailed demand in day k during hour j at demand i, and *VoLL* is the value of curtailed load.

Generation curtailment cost is decided by the curtailed amount, time, duration, and unit price. Depending on market arrangements, the unit price for generators participating in the wholesale market is the wholesale prices while that for smaller generators is the feed-in tariffs (FITs). Thus, the annual curtailment cost for a generator is

$$GCurtail_h = \sum_{k=1}^{365} \sum_{j=1}^{24} \sum_{i=1}^{T} G_{i,j,k} \cdot Pr_{i,j,k} \tag{3}$$

where k is day index, j is hour index, and i is interval index. Pr is the wholesale energy price or FIT at time I, and $G_{i,j,k}$ is curtailed generation.

One essential factor in conducting demand and generation curtailment is the sequence according to various network conditions. Generally, it can be achieved according to importance order or value order, both of which have been utilized in reliability study [21]. In this paper, it assumes that when network congestion appears, the generation that has the most contribution to the congestion is curtailed first, i.e. with the biggest PTDF element. Thereby, another generation is curtailed according to the descending order of PTDF. Once generation curtailment is no longer able to resolve the congestion, load curtailment will be mobilized to resolve the problem.

The operation cost reduction from demand response is quantified by the difference of congestion without and with the demand response.

### 3.3 Network Investment cost

It is assumed that when a branch is overloaded, a new branch is invested to expand its capacity. Thus the annual investment cost discounted into current value is

$$\mathrm{PV} = \frac{Annuity \times AC}{(1+d)^N} \tag{4}$$

where AC is asset cost and d is discount rate. N can be identified by applying a projected load growth rate in the system to determine when overloading happens

$$C = D_0 \cdot (1+r)^N \tag{5}$$

In (4), the PV without DR can be directly obtained by using N from (5).

The PV with DR can be calculated by

$$C = D_{new} \cdot (1+r)^{N_{new}} \tag{6}$$

where $D_{new}$ is the new branch loading level with DR and $N_{new}$ is the branch's new reinforcement horizon.

By submitting $N_{new}$ into (4), it is easy to quantify the present value. The benefits in terms of investment deferral from demand response is the differentness into PV between the cases without and with it

$$\mathrm{Deferral} = PV_{no\ DR} - PV_{with\ DR} \tag{7}$$

## 4. The Proposed Pricing Algorithm

### 4.1 The Algorithm

The proposed pricing algorithm is to find the balance between operation cost and investment cost and then allocates the cost savings to end customers according to their impact on the two costs. Thus, the tariffs to customers are actually benefits. Practically, network operators should choose the cheaper option between investment and operation to resolve network congestion. The signals to customers are actually the savings from the costs of the two options. According to various network conditions, there are two scenarios:

i) When there is no congestion, i.e. the system peak demand is below branch capacity, demand shift or reduction can only defer network investment. The actual cost saving in investment deferral is determined by the change in investment horizon by using (7)

ii) When the system peak demand is above branch capacity, i.e. either curtailment or investment needed, the case becomes complicated. There are three sub-cases here:

- Case 1: annual operational cost is smaller than investment cost. It means that it is economic to resolve system congestion by curtailing generation or load. In this case, demand response during system congestion periods can reduce operation costs. The tariff benefits for end customers who implement demand response are operation only operation cost savings.

- Case 2: annual operational cost is higher than investment cost and thus investment is a better option. Therefore, if customers conduct demand response, the benefits will be from investment cost saving. The allocation of investment cost saving is according to the amount of network operation cost through time.

By forecasting network conditions, system operators can send the signals to end customers based on the potential operation costs and investment costs. According to the information, customers can organise their electricity use and response to it to gain benefits. Operators will conduct billing afterward by examining the contribution of demand response on network operation and investment. Only those customers who implement demand reduction or shifting and have a positive impact on the costs can obtain benefits. If end customers respond to the signals through aggregators, then the signals will be sent to the aggregators, who will be the response for allocating the savings based on customers' contribution.

### 4.2 Accessibility to Dynamic Prices

Operation cost is obtained by time-series analysis at the one-hour interval. Investment cost is translated into hourly based prices by relating it to corresponding operation cost proportionally. If congestion exists on a transmission line, the investment cost should be allocated to the congestion period based on the hourly congestion level. If there is no congestion, the investment cost is allocated to the actual hourly load levels. The positive impact from customers on networks gains benefits but on the contrary, the negative impact from customers will be penalised for paying more of costs.

Only customers who affect network operation costs or investment costs can access dynamic economic signals. This is essential for allocating operation and investment savings or costs among customers in a cost-reflective way.

The allocation is achieved through the following rational: The first step is to identify whether a customer can affect /reduce network operation/investment cost. Only those who can reduce the cost have the accessibility to the elements relating to operation/investment in dynamic price. In this work, it is determined according to the value of PTDF matrix. For demand, if the value of its element relating to a branch is positive, the demand reduction could reduce the branch flow, vice versa.

### 4.2 Implementation Steps

The proposed method mainly consists of three steps: quantification of costs, identification of the access to the dynamic prices and cost allocation.

At the first step, the cost of both investment and operation should be determined. These costs from addressing the congestion on branches by invest a new branch or curtail the load or generation. The lowest addressing method should be selected. If the congestions can be released by the DR, the investment or operation cost to address the congestions transfer to the savings to the DR as the dynamic price, which is the second step. With the cost savings resulting from DR operation, the last step is to allocate these savings to DR as a pricing signal.

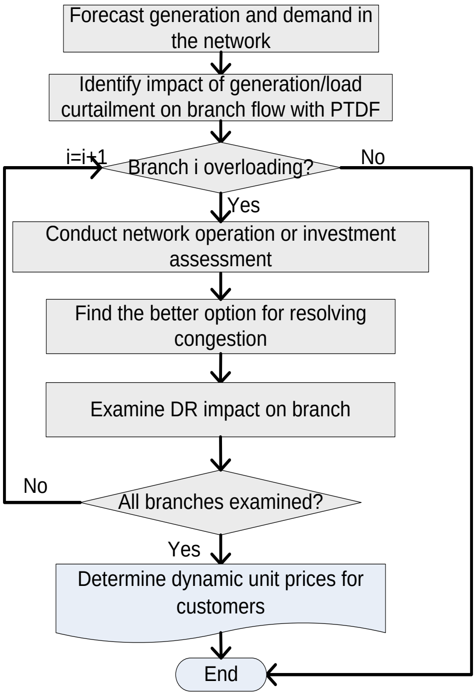


Fig. 2. Flowchart of the proposed algorithm

## 5. Case Study

The proposed concept is demonstrated on a practical Grid Supply Point (GSP) distribution network with 15 buses from the UK [22], shown in Fig. 3. Time-series simulation is conducted to quantify operation costs, where it is assumed that it is the system peak day. The system operation costs are compared with annuitized investment costs to generate economic signals.

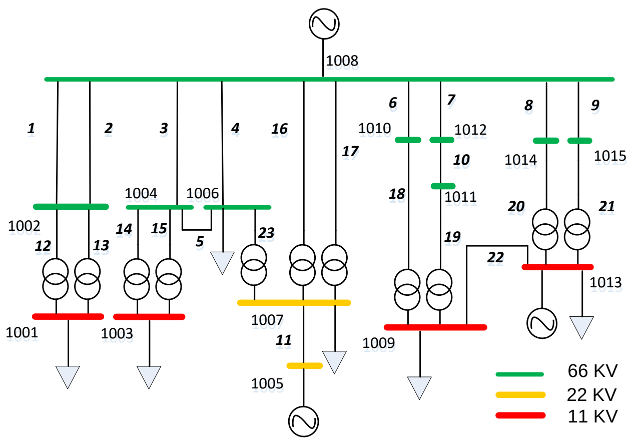


Fig. 3. Configuration of a typical UK EHV network

TABLE I

TIME AND COST OF PRIMARY ASSET INVESTMENT

| *Branch* | *Cost (£m)* | *Present Value (£m)* |
|---|---|---|
| 1008-1007 (16) | 4.4 | 0.36 |
| 1006-1007 (23) | 4.4 | 0.36 |
| 1009-1013 (22) | 0.23 | 0.18 |

The original network investment and annuitized costs are provided in Table I. The lifetime of all components are assumed to be 40 years and a discount rate of 5.6% is chosen. An annuity factor of 0.0831 is used to annuitize the primary costs of all components so that they can be compared with system annual operation costs on the same time scale. The VOLL for the curtailed load is £5400/MW [23].

The typical energy price is obtained from APX, who is responsible for UK electricity market (UKPX RPD) operation. The pricing curves for the two generators are plotted in Fig. 4. Clearly, the price is lower during midnight from 1:00-5:00, but peaks at daytime around 12:30 with the maximum above 84.75£/MWh for G1005 and 71.97£/MWh for G1013.

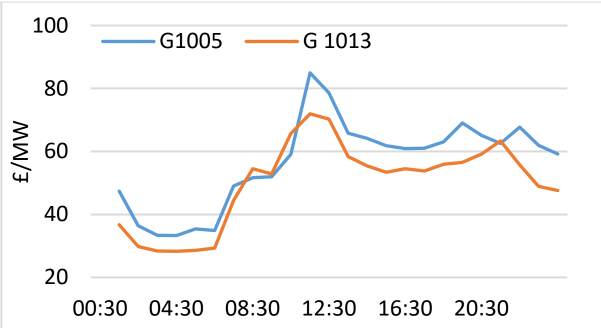


Fig. 4. Energy prices of the two generators [24]

Due to the large scale of PTDF matrix, this section only illustrates the elements that reflect the impact from busbars 1005, 1007 and 1013 on all branches in Table II. It can be seen that with one unit load reduction at bus 1007, lines 11 and 16 are most affected: the power flow from 1008 to 1007 reduces by 0.493 unit but the flow from busbar 1007 to busbar 1005 increases by 0.682 unit.

TABLE II

THE PDTF MATRIX

| Line | 1007 | 1013 | 1005 | Line | 1007 | 1013 | 1005 |
|---|---|---|---|---|---|---|---|
| 1002-1008 | 0.00 | 0.00 | 0.00 | 1002-1001 | 0.00 | 0.00 | 0.00 |
| 1004-1008 | -0.25 | 0.00 | 0.25 | 1004-1003 | 0.00 | 0.00 | 0.00 |
| 1006-1008 | -0.27 | 0.00 | 0.28 | 1004-1003 | 0.00 | 0.00 | 0.00 |
| 1006-1004 | 0.29 | 0.00 | -0.29 | 1008-1007 | -0.44 | 0.00 | 0.45 |
| 1008-1002 | 0.00 | 0.00 | 0.00 | 1008-1007 | -0.40 | 0.00 | 0.42 |
| 1008-1010 | 0.00 | -0.03 | 0.00 | 1010-1009 | 0.00 | -0.03 | 0.00 |
| 1008-1012 | 0.00 | -0.05 | 0.00 | 1011-1009 | 0.00 | -0.05 | 0.00 |
| 1012-1011 | 0.00 | -0.05 | 0.00 | 1014-1013 | 0.00 | -0.04 | 0.00 |
| 1014-1008 | 0.00 | -0.04 | 0.00 | 1015-1013 | 0.00 | -0.04 | 0.00 |
| 1015-1008 | 0.00 | -0.04 | 0.00 | 1009-1013 | 0.00 | -0.83 | 0.00 |
| 1007-1005 | 0.68 | 0.00 | -0.58 | 1006-1007 | -0.37 | 0.00 | 0.39 |
| 1002-1001 | 0.00 | 0.00 | 0.00 | | | | |

### 5.1 System Operation Status

It is assumed that this peak loading day is the only day that load and generation curtailment occurs. By time-series analysis, it is found that branches 1006-1007, 1008-1007, and 1009-1013 are overloaded, whose overloading levels are plotted in Fig. 5. The overloading in 1009-1013 is mainly caused by the excess wind generation at busbar 1013. The maximum overloading appears at 6:00 with the amount of 16MW. For branches1008-1007 and 1006-1007, the overloading from 10:00 to 11:00 are due to the generation at bus 1005. The rest of the overloading is caused by the excessive load at busbar 1007. It should be noted that there is a reverse overloading flow in branches1008-1007 and 1006-1007 during day time around 10:30 pm, which is caused by wind generation output in 1005. The reverse power of branch 1006-1007 is approximately 5MW.

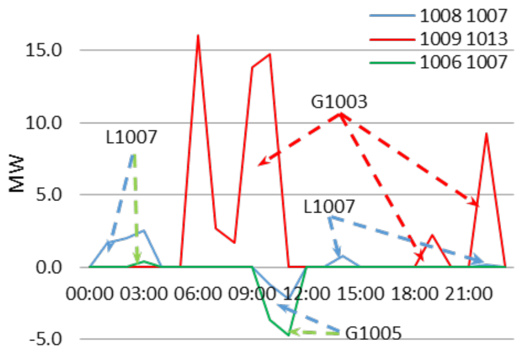


Fig. 5. Overloading levels of selected branches

### 5.2 Quantification of Operation and Investment Costs

In order to resolve overloading, generation and load curtailment is conducted to bring flows below branch capacity. According to the proposed approach, generation at busbars 1005 and 1013, and load at bus 1007 is thus curtailed (shown in Fig.6.), which can address the overloading in selected branches as given in Fig.5. The peak overloading is as high as 16MW on branch 1009-1013 in Fig.6, which is addressed by curtailing 19.3MW of generation at bus 1013 at 06:00. The overloading from 10:00 to 11:00 in branches 1008-1007 and 1006-1007 is addressed by curtailing the generation at busbar 1005for 2 hours with the amount of 22.8 MWh energy. After generation curtailment, the overloading on 1009-1003 is fully addressed but the overloading on other two lines are partially addressed. The rest overloading is addressed by curtailing the load on bus 1007, with the total amount of 18.8 MWh for 4 hours.

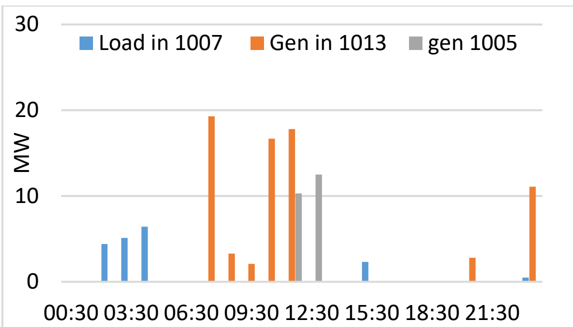


Fig. 6. Load and generation curtailment at selected busbars

The curtailment in the system throughout the peak day and the curtailment cost are summarised in Table III. Clearly, the total generation curtailment is much higher than load curtailment but the cost for load curtailment is much larger. The generation curtailment at bus 1005 costs £1632.4. The generation at 1013 needs to curtail 7 hours with the amount of 73.1 MWh, costing £4523.3. The total generation curtailment costs £6155.7 and the load curtailment costs £101324.4.

TABLE III

ANNUAL CURTAILMENT INFORMATION ON BUSBARS

| | *L 1007* | *G 1005* | *G 1013* |
|---|---|---|---|
| Curtail length (h) | 4 | 2 | 7 |
| Curtailment amount (MWh) | 18.8 | 22.8 | 73.1 |
| Costs (£) | 101324.4 | 1632.4 | 4523.3 |

On the other hand, network operators can choose to invest in overloaded branches to resolving congestions. The annuitized investment cost of the invested branches are provided in Table IV.

TABLE IV

THE INVESTMENT COST FOR OVERLOADING LINES

| Line | investment cost (£) |
|---|---|
| 1009~1013 | 18021.0 |
| 1008~1007 | 36368.4 |
| 1006~1007 | 36368.4 |

Table V shows the comparison of the costs of the two solutions for resolving network congestion. The annual operation costs are smaller than the annual investment cost for branches 1009~1013 and 1006~1007. This means it is better to curtail load and generation which caused congestions on these two branches. Since the annual system operation cost is larger than the annual network investment cost in branch 1008~1007, it is better to invest in this branch.

TABLE V

COMPARISON OF INVESTMENT AND OPERATION COST

| *Busbar* | *Curtailment cost (£)* | *Investment cost (£)* |
|---|---|---|
| 1009~1013 | 4569.4 | 143657.9 |
| 1008~1007 | 128836.6 | 31593.6 |
| 1006~1007 | 1523.2 | 4430.5 |

### 5.3 Price Signals

It is assumed that the DR is realised under the following scenario: 5% of the load on busbar 1001, 20% of the load on busbar 1007 and 10% of generation on bus 1013. The DR responds to network conditions during the peak periods. The contribution of DR to network investment and operation cost are quantified according to the PTDF matrix. The investment cost saving and operation cost savings resulting from DR operation are listed in table VI.

Since there are no congestions on the branches related to the load at bus bar 1001, the operation cost is zero and the DR can only defer network investment because there is no overloading. Thus the price signal only comes from investment cost. The value is £17978.

For customers at busbar 1007, the investment cost is smaller than the operation cost in the most of the transmission lines, which means the investment cost will be the lead factor in the pricing signals. Since the VOLL is correspondingly expensive, the operation cost saving from DR is much higher than the investment cost savings. The negative value resulting from DR is caused by the reversed power flow by DR operation in these branches. For customers at bus1013, the operation cost is smaller than the investment cost because the operation cost is mainly from generation curtailment which is relatively cheap, thus better to curtail the congested energy at this busbar.

TABLE VI

INVESTMENT COST AND CURTAILMENT COST AT VARIOUS DR LEVELS

| From | to | 1001 (DR 5%) | | 1007 (DR 20%) | | 1013 (DR 10%) | |
|---|---|---|---|---|---|---|---|
| | | Investment | Operation | Investment | Operation | Investment | Operation |
| 1002 | 1008 | 3406 | 0 | 0 | 0 | 0 | 0 |
| 1004 | 1008 | 0 | 0 | 7080 | 27518 | 0 | 0 |
| 1006 | 1008 | 0 | 0 | 6765 | 30552 | 0 | 0 |
| 1006 | 1004 | 0 | 0 | -512 | -32183 | 0 | 0 |
| 1008 | 1002 | 7608 | 0 | 0 | 0 | 0 | 0 |
| 1008 | 1010 | 0 | 0 | 0 | 0 | 6540 | 37 |
| 1008 | 1012 | 0 | 0 | 0 | 0 | 21650 | 53 |
| 1012 | 1011 | 0 | 0 | 0 | 0 | 1722 | 51 |
| 1014 | 1008 | 0 | 0 | 0 | 0 | 2281 | 43 |
| 1015 | 1008 | 0 | 0 | 0 | 0 | 4426 | 43 |
| 1007 | 1005 | 0 | 0 | -1 | -75814 | 0 | 0 |
| 1002 | 1001 | 2421 | 0 | 0 | 0 | 0 | 0 |
| 1002 | 1001 | 4544 | 0 | 0 | 0 | 0 | 0 |
| 1004 | 1003 | 0 | 0 | 1 | 7 | 0 | 0 |
| 1004 | 1003 | 0 | 0 | 1 | 6 | 0 | 0 |
| 1008 | 1007 | 0 | 0 | 8230 | 48848 | 0 | 0 |
| 1008 | 1007 | 0 | 0 | 6560 | 44983 | 0 | 0 |
| 1010 | 1009 | 0 | 0 | 0 | 0 | 1541 | 36 |
| 1011 | 1009 | 0 | 0 | 0 | 0 | 1599 | 50 |
| 1014 | 1013 | 0 | 0 | 0 | 0 | 926 | 42 |
| 1015 | 1013 | 0 | 0 | 0 | 0 | 921 | 42 |
| 1009 | 1013 | 0 | 0 | 0 | 0 | 19059 | 908 |
| 1006 | 1007 | 0 | 0 | 7320 | 41398 | 0 | 0 |

Fig.7. shows the economic signals to the DR at busbar 1001. Since there are no operation cost savings resulting from DR in busbar 1001, the investment cost savings are allocated to the load based on the loading levels. There for the unit price for each period is flat which is £439.2/MW.

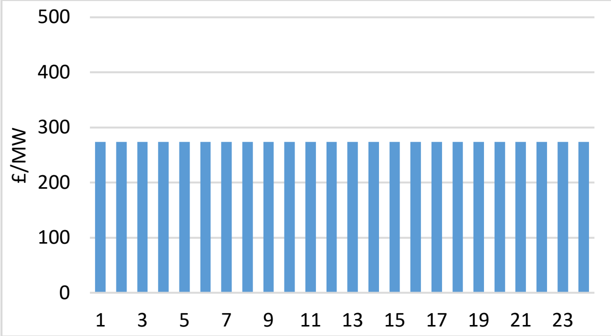


Fig. 7.  The economic signal to DR on busbar 1001

Fig.8. shows the economic signals to the DR at busbar 1007. If the DR works during 03:00 to 04:00 and 11:00 to 12:00, the unit pricing for DR is higher than another period which means DR can gain more benefits from network cost savings. Since the curtailment on this busbar is load curtailment, the loss of load cost is much higher than the former two cases which means DR can gain more benefits it helps to reduce the congestions. DR can gain the maximum profit at 12:00 which is £4783/MW. The DR can gain high profits because the congestion cost at branches 1008~1007 and 1006~1007 is dramatically high during this period.

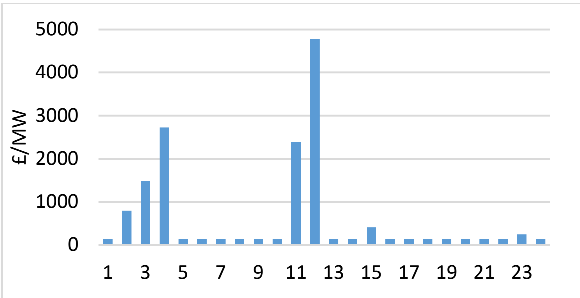


Fig. 8.  The economic signal to DR on busbar 1007

Fig.9. shows the economic signals to the DR at busbar 1013. The DR will have better benefits if it works during 07:00 to 11:00 and 23:00 DR can gain the maximum profit at 10:00 to 11:00 which is £2321/MW from investment cost savings from related branches.

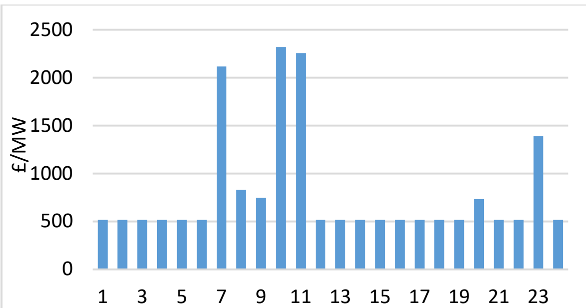


Fig. 9. The economic signal to DR on busbar 1013

## 6. Conclusions

Demand response is playing an essential role in smart grids considering the extensive benefits it can bring along. Different from most current research that design economic signals only considering energy costs, this paper designs economic signals that reflect demand response's impact on network operation and investment. Through extensive demonstration, the following key observations are obtained.

- Network costs take up a large proportion of cost for customer bills, where the demand response's contribution to network investment/operation savings has to be respected.
- Demand and generation contribute positively or negatively to network investment and operation, which can be measured by the PTDF matrix.
- A balance between operation cost saving and investment cost saving should be sought so that the appropriate economic signals are sent to customers.

Currently, advanced system operation, such as active distribution network management, is not considered, which however can reduce system operation and investment costs. Our future work will examine the impact of optimal system operation and further include the savings into economic singles to demand response.


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