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Locational marginal emissions: Analysis of pollutant emission reduction through spatial management of load distribution

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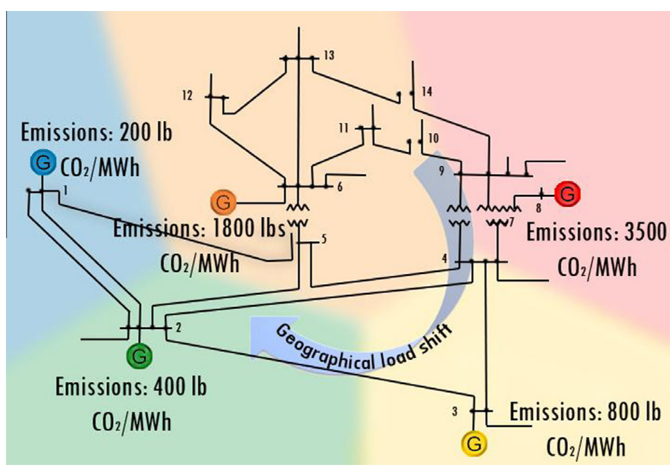
HIGHLIGHTS

- Locational marginal emissions provide mechanism for demand-side pollutant reduction.
- Simulation study using IEEE 14-bus system and PJM regional transmission system.
- Spatially optimizing loads using LME decrease CO_2, SO_2 and NO_x emissions 3–6%.
- Generator diversity and spatial flexibility of loads increase LME effectiveness.

GRAPHICAL ABSTRACT

Reduction of environmental pollution based on dynamic load reallocation using locational marginal emissions (LMEs).



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ABSTRACT

Environmental concerns associated with power generation drive an increasing interest in developing load management strategies to reduce pollutant emissions. Currently, no mechanism exists to directly influence pollutant emissions based on demand-side decisions. This shortcoming is addressed through the exploration of an alternative load distribution management paradigm based on the use of locational marginal emissions (LMEs). LMEs present a novel mechanism for optimizing load based on pollutant emissions. To demonstrate the application of LMEs, simulation studies using the IEEE 14-bus system and a large regional transmission system in the US (PJM) were performed and changes in CO_2, SO_2, and NOx emissions were quantified for varying levels of spatial load flexibility. The simulation results confirm that the proposed LME-based load management method is effective in reducing pollutant emissions in comparison to the traditional economic load distribution management method based on the locational marginal price (LMP). Emission reductions were found to become more significant as the proportion of spatially controllable loads increased. Adoption of LMEs by independent system operators (ISOs) or Regional Transmission Organizations (RTOs) would empower demand-side clients to reduce pollutant emissions based on their own load management decisions and enhance the sustainability of free-market

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power systems. Alternately, the LME management scheme could be automated by utilities through connections to Smart Grid compatible appliances.

Nomenclature

BLD	base load distribution
EPA	US Environmental Protection Agency
GHGs	greenhouse gases
ISOs	independent system operators
LME	locational marginal emission
LMP	locational marginal price
MATS	Mercury and Air Toxics Standards
OLD	optimal load distribution
OPF	optimal power flow
RTOs	Regional Transmission Organizations

1. Introduction

In recent years, there has been increasing attention on the impacts of air-borne contaminants, including greenhouse gases, acid rain precursors, and mercury, pollutants that are responsible for climate change, terrestrial contamination, uptake of toxins in the food chain, asthma and other related health impacts. The electric power industry is a major source of air pollutant emissions. For example, in the US, about 40% of all CO_2 emissions are attributed to electricity generation [1]. While CO_2 and other pollutants responsible for climate change have yet to be regulated in the US, new findings that they constitute a threat to public health and welfare under Section 202(a) of the Clean Air Act pave the way for additional regulations by the US Environmental Protection Agency (EPA). Mercury is an example of a pollutant that has received increased attention recently, particularly in the Great Lakes region. Due to pollutant loadings from power plants, strict environment protection laws have been enacted, including the Mercury and Air Toxics Standards (MATS) and more are proposed [2,3].

Traditional power system management typically limits the information available to users interested in reducing pollutant emissions. To quantify pollutant emissions resulting from a given power demand, high-resolution data describing power generation and transmission is required [4]. Weber et al. [4] provides an excellent discussion outlining data constraints to assessing pollutant emissions within the US power grid. Major parts of the US power grid are organized into Independent System Operators (ISOs) or Regional Transmission Organizations (RTOs). The locational marginal price (LMP), typically reported by the ISO every five minutes, is one piece of distributed data available to assist in demand side scheduling. Conceptually, LMPs represent the cost to serve the next incremental unit of load at a particular time and place [5,6]. LMPs are derived from an optimization designed to minimize the cost of generation using generator outputs as control variables. Because low cost fuel (such as coal) fired generators often have high emission factors, LMPs are not expected to be a direct measure of emissions impacts and therefore it is not surprising that, in some cases, LMP-based load distribution schemes may not reduce emissions, and in some cases my even increase emissions [7].

To better coordinate environmental and economic objectives in the electrical power generation industry, many types of generator dispatch algorithms, including the classic Newton–Raphson and Lagrange multiplier methods [8–10] and the heuristic/evolutionary approaches [11–15] have been developed. However, most of these algorithms focus on emission reduction through management at the generator side, overlooking the potential of load distribution management as an independent mechanism to reduce net generator emissions output. Given proper incentives, information, and assuming control over load distribution across the grid, consumers could play an active role in emission reductions through energy consumption decisions [16].

Using the concept of locational marginal emissions (LMEs), this paper develops a mechanism for apportioning loads among several locations (spatial flexibility) to minimize emissions in real-time. This approach could be utilized by a single demand side consumer, such as a large water utility that has multiple pumps distributed spatially across a power system, or by multiple demand side consumers, each with the ability to alter their power demands (e.g., electing when to charge electric vehicles), connected through a Smart Grid. Simulations are first carried out on the standard IEEE 14-bus system [17]. By comparing the different spatial load distributions resulting from both LMP-and LME-based approaches, the relative merit of an LME-based approach is evaluated and its potential application to real power systems is discussed. Moreover, the LME method is further investigated and validated on a model of the PJM interconnection system [18].

2. Spatial load distribution management

Conceptually, the spatial load distribution management proposed in this paper can be described as a form of Demand Side Management (DSM). By altering the amount of electricity used by individual consumers, DSM can change the shape utility loads [19]. In this paper we utilize a novel application of DSM. Rather than a typical DSM strategy that might shift loads from on-peak periods to off-peak periods [20,21], we present an approach where the load is distributed spatially and evaluate the result on pollutant emissions.

For clarity, it is helpful to highlight two features of electric power dispatches. First, large amounts of electricity cannot be effectively stored within power systems; hence, power must be balanced at each point in time (i.e., generator outputs must equal the sum of loads and power losses). Therefore, increasing/decreasing the total amount of loads will directly alter generator outputs. Secondly, it is very common to have congestion conditions (e.g., capacity limits of transmission lines) in power systems. When congestion occurs, different load distributions will influence the dispatch of generation, even if the total load is unchanged. Therefore, changes in load and distribution will also affect generator outputs and ultimately impact pollutant emissions even when the total amount of generation remains constant.

In the following sections, the potential impact of optimal spatial load distribution on pollutant emissions is evaluated using a generator cost model, a generator emission model and two optimal models for load distribution.

2.1. Generator cost model

The heat rate of a fossil fuel-fired generation unit was modeled as a quadratic function of its active power output [21]. The generation cost of the unit can be expressed as

$$G_i(P_{Gi}) = F_i(k_{i2}P_{Gi}^2 + k_{i1}P_{Gi} + k_{i0}) \quad (1)$$

where G_i ($/MW h) denotes the generation cost of generator i; p_{Gi} (MW) is the active power output of generator i; F_i ($/MMBtu) denotes the fuel price of generator i; k_{i2}, k_{i1} and k_{i0} are the polynomial coefficients of the heat rate function and are calculated based on the heat rate curve of the generator.

2.2. Generator emission model

The emissions (lbs/MW h) of the generation unit can be expressed as a function of the heat rate of the generation unit [10,22]:

$$E_{ij}(P_{Gi}) = ef_{ij}(k_{i2}P_{Gi}^2 + k_{i1}P_{Gi} + k_{i0}) \quad (2)$$

where ef_{ij} represents the emission factor (lbs/MMBtu) of generator i for pollutant j, where j can be 1, 2 and 3 representing CO_2, SO_2 and NOx, respectively.

2.3. Optimal power flow

If the generator cost and emissions are optimized together within the OPF [23], the objective function becomes:

$$\min_{P_{Gi},Q_{Gi};V_j,\theta_j} \sum_{i=1}^{n_g} C_i(P_{Gi}) = \sum_{i=1}^{n_g}\left(F_i + \sum_{j=1}^{3} p_{rj} \times ef_{ij}\right) \cdot (k_{i2}P_G i^2 + k_{i1}P_{Gi} + k_{i0}) \quad (3)$$

subject to

$$P_{Gi} - P_{Di} = V_i \sum_{j=1}^{N} V_j(g_{ij}\cos(\delta_i - \delta_j) + b_{ij}\sin(\delta_i - \delta_j)) \quad i = 1, \ldots, N \quad (4)$$

$$Q_{Gi} - Q_{Di} = V_i \sum_{j=1}^{N} V_j(g_{ij}\sin(\delta_i - \delta_j) - b_{ij}\cos(\delta_i - \delta_j)) \quad i = 1, \ldots, N \quad (5)$$

$$\left[V_m^2(g_{m0} + g_{mn}) - V_mV_n(b_{mn}\sin(\delta_m - \delta_n) + g_{mn}\cos(\delta_m - \delta_n))\right]^2 + [-V_m^2(b_{m0} + b_{mn}) + V_mV_n(b_{mn}\cos(\delta_m - \delta_n) - g_{mn}\sin(\delta_m - \delta_n))]^2 \leqslant (s_{mn}^{\max})^2 \quad (6)$$

$$P_{Gi}^{\min} \leqslant P_{Gi} \leqslant P_{Gi}^{\max} \quad i = 1, \ldots, n_g \quad (7)$$

$$Q_{Gi}^{\min} \leqslant Q_{Gi} \leqslant Q_{Gi}^{\max} \quad i = 1, \ldots, n_g \quad (8)$$

$$V_i^{\min} \leqslant V_i \leqslant V_i^{\max} \quad i = 1, \ldots, N \quad (9)$$

$$-\pi \leqslant \delta_i \leqslant \pi \quad i = 1, \ldots, N \quad (10)$$

where P_{Gi} and Q_{Gi} denote the generator output active and reactive power, respectively; P_{Di} and Q_{Di} are the load active and reactive power; V_i, V_j, V_m, V_n and δ_i, δ_j, δ_m, δ_n are the voltage magnitude and angle at node i, j, m and n, respectively; n_g and N are the number of generators and total nodes in the system; F_i represents the fuel price ($/MMBtu); p_{rj} (j = 1, 2, 3) is the price of the jth pollutant to calculate emission cost; k_{i2}, k_{i1} and k_{i0} are the heat polynomial coefficients, which are calculated in terms of the heat curve of generators. g_{mn} and b_{mn} are the real and imaginary parts of the admittance of line m/n; g_{m0} and b_{m0} are the equivalent line admittance from bus m to ground.

The optimal power flow Eqs. (3)–(10) combine to determine the generator dispatches in response to changes in load and distribution. The power flow model based on these equations can be used to investigate how a variety of load distribution schemes (presented in the next section) can alter generator outputs and eventually impact pollutant emissions.

2.4. Optimal load distribution (OLD)

Because of the inconsistency between economic and environmental targets and the fact that low cost fuel-fired generators (such as coal) often have high emission factors, the optimal economic-based power dispatch (traditional OPF) often results in non-optimal emission outputs. In the present research, the concepts of Locational Emissions Estimation Methodology (LEEM) and LME, introduced by Rogers et al. [24], are applied in demand-side management for emission reductions. Similar to LMP, LME refers to the marginal emissions attributed to a unit load change (decrease/increase) at a specific node. The OLD based on LME, namely OLD_{LME}, assumes (1) the real-time LME values are available for demand management decisions and (2) the total load in the power system remains unchanged (i.e. the sum of the distributed loads is constant) under the load redistribution scenario. Based on LMEs known in advance of demand management, a new optimal load management model is proposed where the objective function is described as

$$\min_{\Delta P_{Di}} \sum_{i=1}^{n_d} (LME_i \times \Delta P_{Di}) \quad (11)$$

and is subject to

$$\sum_{i=1}^{n_d} \Delta P_{Di} = 0 \quad (12)$$

$$p_{Di}^{\min} \leqslant p_{Di0} + \Delta p_{Di} \leqslant p_{Di}^{\max} \quad i = 1, \ldots, n_d \quad (13)$$

where P_{Di0} and ΔP_{Di} represent the load "i" before optimization and the corresponding load change after optimization, respectively. Load i is limited to vary within an available range ($p_{Di}^{\min}, p_{Di}^{\max}$). Generally speaking, the available range for load modification is determined by the proportion of spatially flexible load and the overload capability of each load node. LME_i is the locational marginal emission at load node i (lbs/MWh). n_d is the total number of controllable load buses.

For comparison purposes, the OLD model based on LMPs, namely OLD_{LMP}, is investigated by replacing LME_i in Eq. (11) with LMP_i at node i. The following equation results:

$$\min_{\Delta P_{Di}} \sum_{i=1}^{n_d} (LMP_i \times \Delta P_{Di}) \quad (14)$$

The emissions attributed to the demand distribution are calculated for both OLD_{LME} and OLD_{LMP} under a variety of load flexibility scenarios.

The computational steps associated with calculating LME and OLD are presented in Fig. 1. The OPF model predefined by the ISO determines the mechanism of generator dispatch for any load changes during a given time frame in an ISO system. In Fig. 1(a), given a typical load profile, a marginal (1 MW) load is added to each load node and the LME for that node is calculated as the difference in generation emissions (Eq. (2)) before and after the 1 MW load increase. A lookup table of LMEs for different load levels associated with a typical load profile (e.g., 70%, 80%, 90%, and 100% of the base load) is obtained which can then be provided to electricity

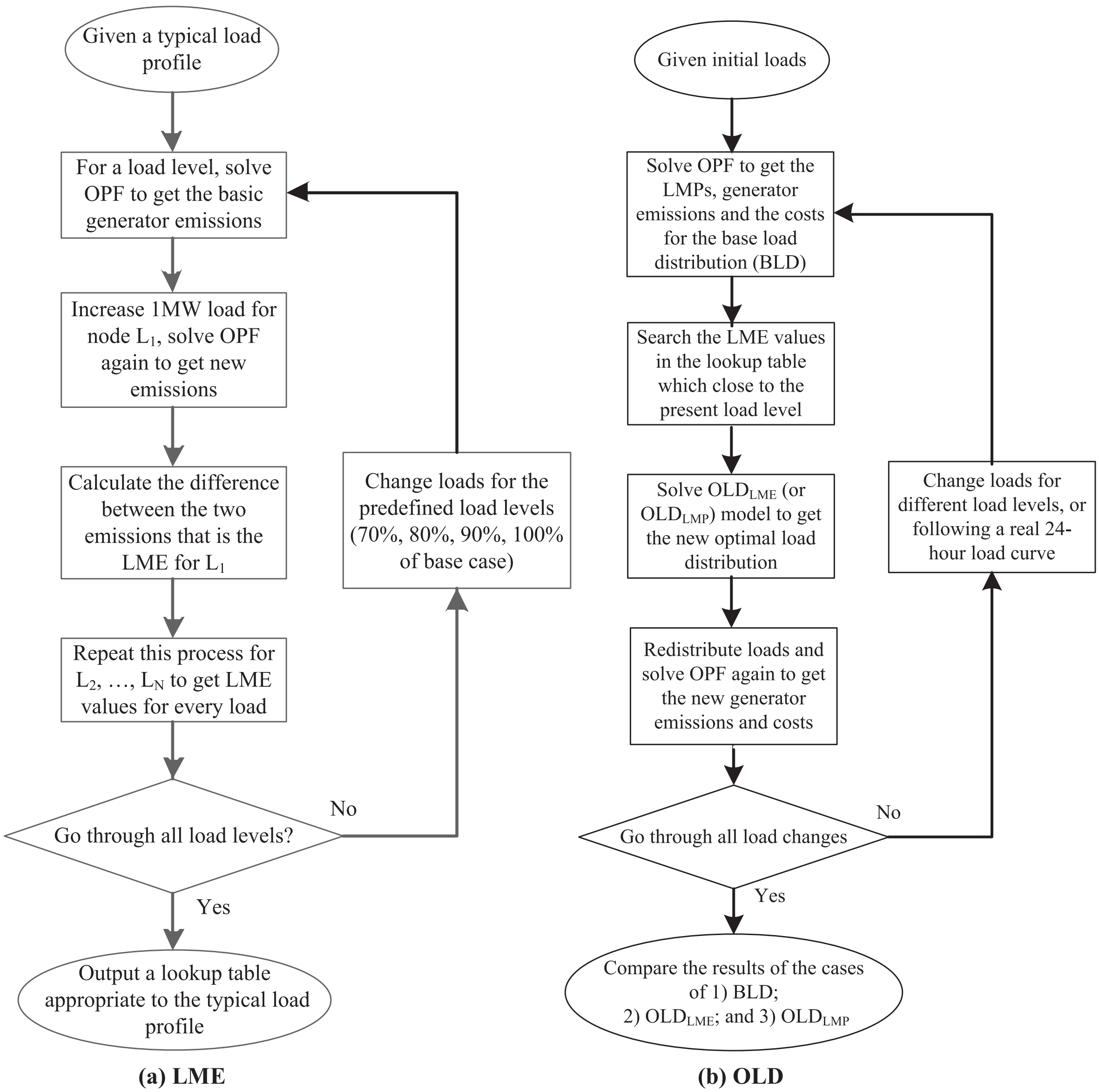

Fig. 1. Flowchart for (a) LME and (b) OLD calculations.

clients for making demand management decisions. In this paper, the LME calculation is completed by an off-line simulation, but this could be performed on-line using real-time LMP data.

Once the LMEs (at different load levels) for each load bus are obtained, the question becomes whether spatially redistributing loads based on LME information can be used to reduce emissions resulting from electricity generation. In other words, if users redistribute their loads from one location to another through the use of Eqs. (11)–(13), what will happen to the emissions and costs associated with electricity generation? To address the above question, a simulation study was carried out, as presented in Fig. 1(b). The simulation process was repeatedly carried out for each load level (or each load point on a 24 h load curve). Note that in a real system, generator dispatch is automatically assigned based on the OPF at ISOs every few minutes. Within this framework, electricity customers do not need to know the details in OPF calculation, receiving only real-time price information (i.e. LMP) required to manage system loads. Ultimately, because LMEs can be reasonably estimated based on published LMPs [24], electricity consumers (i.e. users) *do not require new information about system operations from ISOs* to spatially distribute/manage their own loads to reduce pollutant loads. Likewise, industry-based (e.g., appliance manufacturers) tools for such management are currently feasible.

3. Numerical studies

The simulation studies were first completed on a modified IEEE 14-bus system. This system consists of 14 buses, 5 generators, 18 branches, 2 transformers, a total of 259 MW load (see Table 1) and 360 MW generator capacity. As described in Table 2, the generators included a 200 MW coal generator at node 1, a 100 MW natural gas generator at both nodes 2 and 3, and a 60 MW oil generator at both nodes 6 and 8. Details of the fuel prices and emission factors for the three generator types are provided in Tables 3 and 4. In order to introduce constraint scenarios, the transfer capability of line 1/5 in Fig. 2 was reduced to 50 MW. Significant line constraints exist in present day power systems when high transfer levels approach physical limitations.

The impact of spatial management of load distribution on emission reduction was then explored on a model of the PJM

Table 1
Loads for base case model (100% level).

Load	Node													
	1	2	3	4	5	6	7	8	9	10	11	12	13	14
(MW)	0.00	21.70	94.20	47.80	7.60	11.20	0.00	0.00	29.50	9.00	3.50	6.10	13.50	14.90

Table 2
Generator active power.

	Node				
	1	2	3	6	8
Generator capacity (MW)	(Coal) 200	(Gas) 50	(Gas) 50	(Oil) 30	(Oil) 30

Table 3
Fuel prices.

	Type of fuel		
	Coal	Gas	Oil
Price ($/MBtu)	2.05	9.05	12.00

Table 4
Emission factors.

Emission	Type of fuel		
	Coal	Gas	Oil
CO_2 (lbs/MBtu)	210.97	101.16	134.62
SO_2 (lbs/MBtu)	1.2195	0.0089	0.9662
NO*x* (lbs/MBtu)	0.5629	0.1515	0.3221

interconnection system, which consists of 17 control areas (FE, AEP, DLCO, CE, PJM, PENELEC, METED, JCP&L, PPL, PECO, PSE&G, BGE, PEPCO, AE, DP&L, UGI, RECO), 9491 buses, 6652 branches, a total 1031 generating units of 155135.31 MW and 102993.19 MW loads. The data, corresponding to the system state of Eastern Interconnection (EI) in 2012 winter, was provided by the Federal Energy Regulatory Commission (FERC). The following scenarios were tested using the commercial power system software PowerWorld™ [25] to evaluate the effectiveness of spatial load distribution: (1) base load distribution (BLD) without optimization, (2) load distribution optimized using LME, and (3) load distribution optimized using LMP.

For the purpose of analysis, CO_2 was used as a model pollutant. Interest in climate change and the possibility of taxing CO_2 emissions made this an ideal pollutant to evaluate the utility of the LME approach. As such, arbitrary costs of CO_2 were considered during simulation studies presented in this paper. In other words, only p_{r1} was included in the generation cost model in Eq. (3). Other pollutants could readily be included if desired

3.1. IEEE 14 bus system simulations

Initially, the price of CO_2 was assumed to be zero and only fuel costs were considered in the OPF model (i.e., $p_{r1} = 0$ in Eq. (3)). This corresponded to the traditional OPF. Two types of load changes, namely, different load levels and time-varying load profiles within 24 h were explored. As shown in Fig. 1(b), to evaluate emissions reductions via OLD the following scenarios were investigated: (1) the base load distribution (BLD) without optimization, (2) distribution optimized using LME (OLD_{LME}), and (3) distribution optimized using LMP (OLD_{LMP}). Moreover, the sensitivity of the load distribution and generator emissions resulting from CO_2 pricing were also studied.

3.1.1. LME versus LMP

LME values of CO_2, shown in Table 5, were calculated at each node and for each of the four load levels (70%, 80%, 90% or 100%) using the methodology described in Fig. 1(a). Accordingly, LMEs for each load level were determined by multiplying the base loads presented in Table 1 by each of the four load levels. Because LMPs are the values of the Lagrange multipliers regarding the active power balance Eq. (4), the LMPs for each load level (Table 6) were

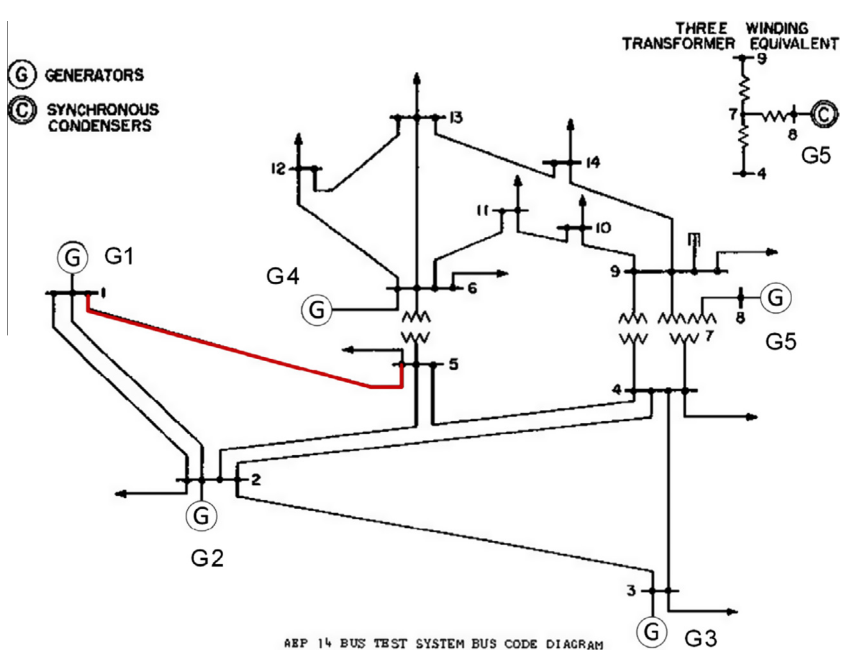

Fig. 2. IEEE14-bus model system [17] used for simulations.

Table 5
LME values of CO_2 at various nodes (lbs/MW h).

Load level (%)	Load node										
	2	3	4	5	6	9	10	11	12	13	14
70	1401.47	1088.23	737.53	497.85	574.47	675.15	659.79	619.43	588.79	597.00	649.68
80	1323.75	966.12	604.78	347.61	429.91	537.08	520.58	477.46	444.48	453.12	509.34
90	1426.25	1128.19	832.53	613.35	683.81	777.10	764.91	727.61	702.41	711.25	763.96
100	1203.40	810.25	428.50	151.96	241.65	354.27	336.32	290.88	254.69	263.32	321.81

Table 6
LMP at various nodes ($/MW h).

Load level (%)	Load Node													
	1	2	3	4	5	6	7	8	9	10	11	12	13	14
70	19.2	21.8	23.9	24.3	24.7	24.5	24.4	24.4	24.5	24.6	24.6	24.7	24.8	25.0
80	19.1	42.0	56.3	66.3	73.2	70.6	67.7	67.7	68.5	69.2	70.1	71.3	71.4	70.9
90	19.1	48.6	66.5	80.4	89.6	86.1	82.3	82.3	83.3	84.2	85.4	87.1	87.2	86.6
100	18.8	60.0	85.4	105.2	118.2	113.5	107.9	107.8	109.3	110.7	112.4	114.9	115.2	114.3

directly obtained in the process of solving the optimal power flow (OPF) for the base case [5], similar to how they would be determined in a real system by an ISO.

Due to the fact that low cost coal-fired generators have high emission factors, and the opposite is true for the gas and oil generators in this case, economic-based load management often results in increased emissions. In Tables 5 and 6, the values of LMPs and LMEs, which reflect the financial cost (i.e. money) and the environmental cost (i.e. emissions) for the next incremental unit of load at a particular time and place, are inconsistent. The load node with a higher LMP often has a lower LME, and vice versa. This phenomenon indicates that the emissions will increase if the loads are redistributed according to the cost-based indicator: LMP.

At the 70% load level, LMEs (and LMPs) across the system are relatively constant. The slight differences of LMEs (or LMPs) are due to power losses on transmission lines. In the simulations under these circumstances, only the coal-fired generator – which has the lowest cost – will be responsible for the 1 MW load increase no matter where the marginal load is applied. A program employing OLD would ideally inform a prospective user not to shift loads as this will not impact emissions. However, for larger load levels (80% and greater), the LMEs (and LMPs) vary significantly between nodes. This indicates that, due to the impact of line constraints, the marginal unit types expand to include different generators and fuel types. In some extreme cases, the marginal 1 MW load increase may lead to negative emission changes if the "dirtier" generators decrease their output with a corresponding increase in the output of "cleaner" energy generators.

3.1.2. Emissions at different load levels

The effectiveness of the LME-based optimal load distribution (OLD_{LME}) method is investigated under variable load levels (from 65% to 105% of the base load level for the system-wide load) and different levels of nodal load flexibility (±20%, ±40% and ±60% of nodal load). Note that the test load level here is different from the load levels selected to calculate the LME lookup tables. For a specific load level, the closest LME value in the lookup table was selected for the OLD_{LME} calculation. The maximum nodal load was limited to 120% of its base value. Emissions of CO_2, SO_2, and NOx and the generation costs are plotted versus load levels ranging from 65% to 105% for the case of LME-based optimal load distribution (OLD_{LME}) in Fig. 3(a–d). For comparison, the emission and cost results of the LMP-based optimal load distribution (OLD_{LMP}) method are plotted in Fig. 3(e–h). Included within these figures are the system responses to the base case (without spatial load management) and the three levels of spatially flexible loads.

According to the results presented in Fig. 3, the OLD_{LMP} approach increases emissions while the OLD_{LME} approach reduces emission. A spatial load flexibility of ±60% in OLD_{LME} reduce 8% of CO_2, 10% of SO_2 and 10% of NOx emissions compared to the base load distribution (BLD) without optimization. Moreover, when compared to the OLD_{LMP} approach, the reductions obtained using OLD_{LME} can be as high as 16%, 20% and 20% for CO_2, SO_2 and NOx, respectively. In this system, the OLD_{LME} method is also most efficient under moderate load levels (70–95%). When loads are less than 70%, the most economical generator (i.e. coal-fired) will respond to the change in load. Under these circumstances, significant reductions in emissions cannot be achieved without changing fuel types in the OLD_{LME} load distribution. Alternatively, under heavy load situations (i.e. load levels >95% capacity) the OLD_{LME} method is constrained by the overload capability limitations (set at 120% in this paper). As a result, OLD_{LME} method is capable of reducing pollutant emissions for moderate load levels (i.e. load levels of 70–95%). Furthermore, as shown in Fig. 3, significant emission reductions are observed at load levels that are slightly lower using the OLD_{LME} approach (approximately 70%) than the OLD_{LMP} approach. This is likely due to the OLD_{LMP} method reducing line constraints [22]. Meanwhile, the emission reductions achieved using the OLD_{LME} result in slightly higher costs (Fig. 3(d and h)). As a result, proper economic incentives would likely be needed to effectively implement OLD_{LME}.

3.1.3. Emissions over a diurnal time period

The effectiveness of the LME-based OLD method (i.e. OLD_{LME}) is further investigated over a 24 h simulation period with varying loads. The load profile shown in Fig. 4 is based on the July 2010 load of a mid-size water utility in southern Michigan. Typical of summer load curves, the distribution is bimodal, peaking in the morning and again in late evening. For this simulation, load variations of ±40% are permitted while shifting loads spatially. The diurnal variation in emissions resulting from this simulation is presented in Fig. 5, while Table 7 provides the cumulative emissions and costs for the 24 h period (see the rows related to zero CO_2 cost in Table 7).

Results suggest that the daily CO_2, SO_2 and NOx emissions can be decreased by approximately 3%, 6% and 6%, respectively, when the OLD_{LME} method of load distribution is compared to the base load distribution without any optimization (i.e. BLD). It is also useful to compare the daily emissions from the LME-based load distribution to the emissions obtained from the most "cost-effective" load distribution determined through the use of LMP in the distribution optimization algorithm. Relative to the

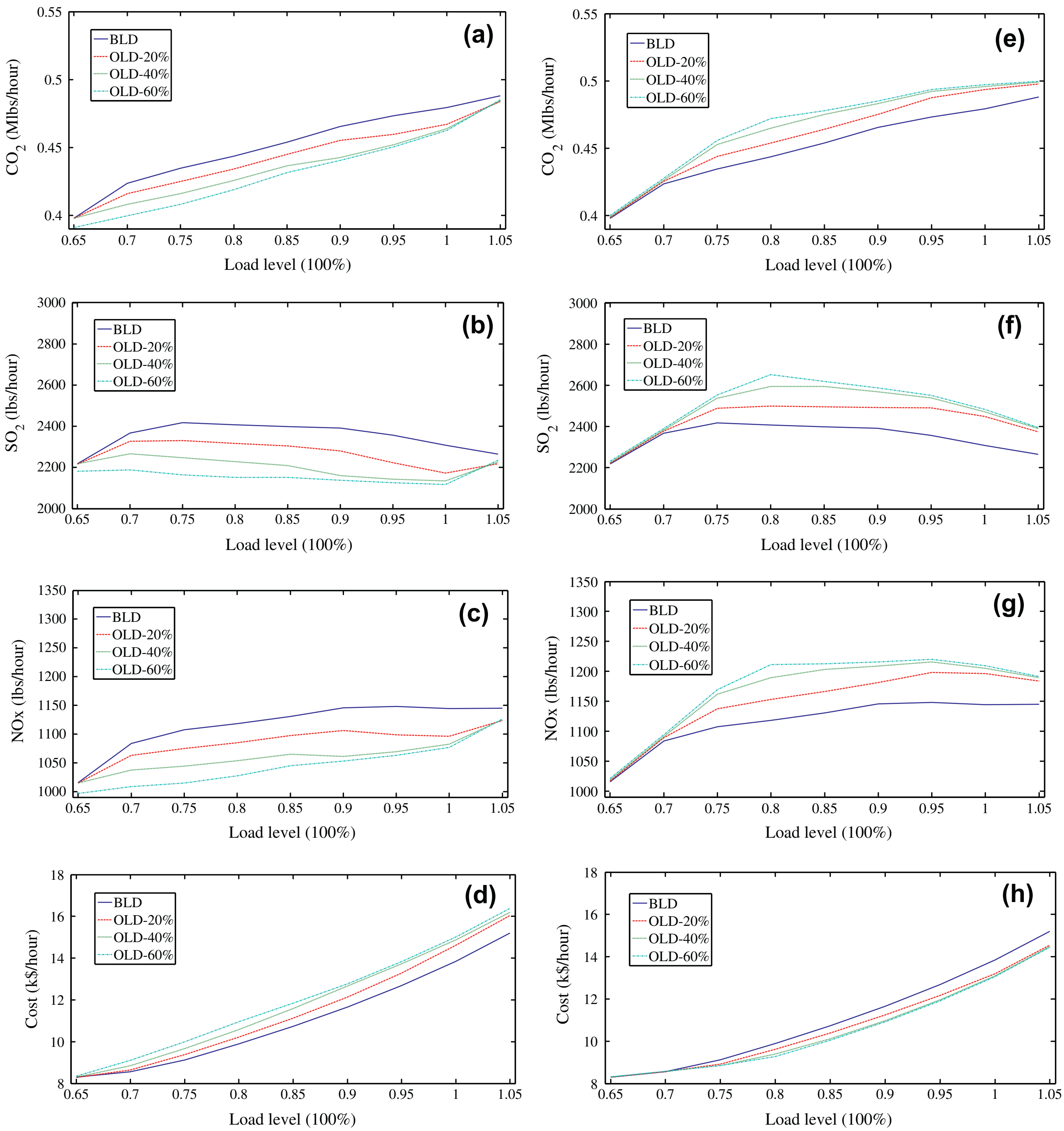

Fig. 3. CO_2 (a and e), SO_2 (b and f), NO*x* (c and g) emissions and generation costs (d and h) resulting from OLD levels using the LME (left panel, a–d) versus LMP (right panel, e–h) approach based on the IEEE 14-bus system.

OLD_{LMP} method, emissions are further reduced 7%, 13%, and 12% for CO_2, SO_2 and NO*x* emissions, respectively. However, these improvements in emissions come with additional costs. The application of the OLD_{LME} method for emission reductions resulted in an increase in generation costs of 6% and 10% over the cost associated with the BLD and OLD_{LMP} methods, respectively.

3.1.4. The impact of CO_2 pricing

In order to investigate the impact of CO_2 pricing, it is assumed the unit price of CO_2 ranged from $0 to $100 per thousand pounds in Eq. (3). Meanwhile, the typical daily load curve (Fig. 4) and 40% flexibility for spatial demand management were used for this evaluation. The total emissions and total costs with respect to the different CO_2 prices and three types of load distribution schemes (BLD, OLD_{LME} and OLD_{LMP}) are shown in the Table 7.

From Table 7, the following observations are made:

- Incorporating the cost of CO_2 emissions into the generation cost model is an efficient method to decrease emissions in the OPF algorithm. When the price of CO_2 is as high as $100/klbs, an

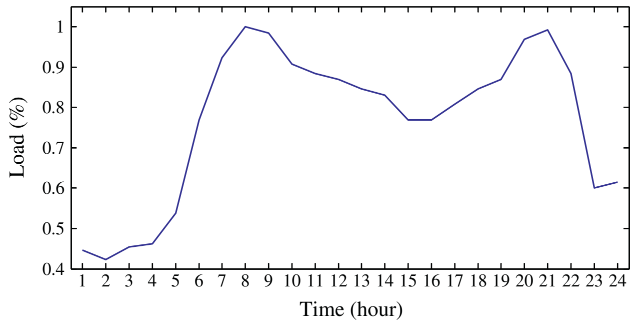

Fig. 4. A typical hourly load curve based on water demands in July 2010. Water demand is for a mid-size community in southern Michigan – drawing water from Lake Erie and serviced by Detroit Edison.

approximate 1.65 Mlbs reduction in CO_2 can be realized over a 24 h period relative to the current scenario where no addition costs are associated with CO_2 emissions (Table 7).

- The OLD_{LME} method can be still considered to reduce emissions when the CO_2 price is relatively low, under $5/klbs (a number close to CO_2 prices currently trading at auction in the Northeastern US [26]). About 3.3% of CO_2, 6.6% of SO_2 and 5.0% of NO*x* can be decreased using OLD_{LME}.
- The results of OLD_{LME} and OLD_{LMP} gradually become identical when the price of CO_2 increases. In fact, from Eq. (3), LMEs are approximately equal to LMPs divided by the unit price of CO_2 if the CO_2 price is high enough and dominates the generation cost.

3.2. PJM system simulation

In the simulation studies of the PJM system, the load demands (of Winter 2012) were spatially distributed among different control areas according to their LME and LMP values given in Table 8. In other words, each control area was treated as a whole when the loads were shifted spatially. Real fuel prices were used in the simulation studies. It is assumed that 8% of loads in every control area

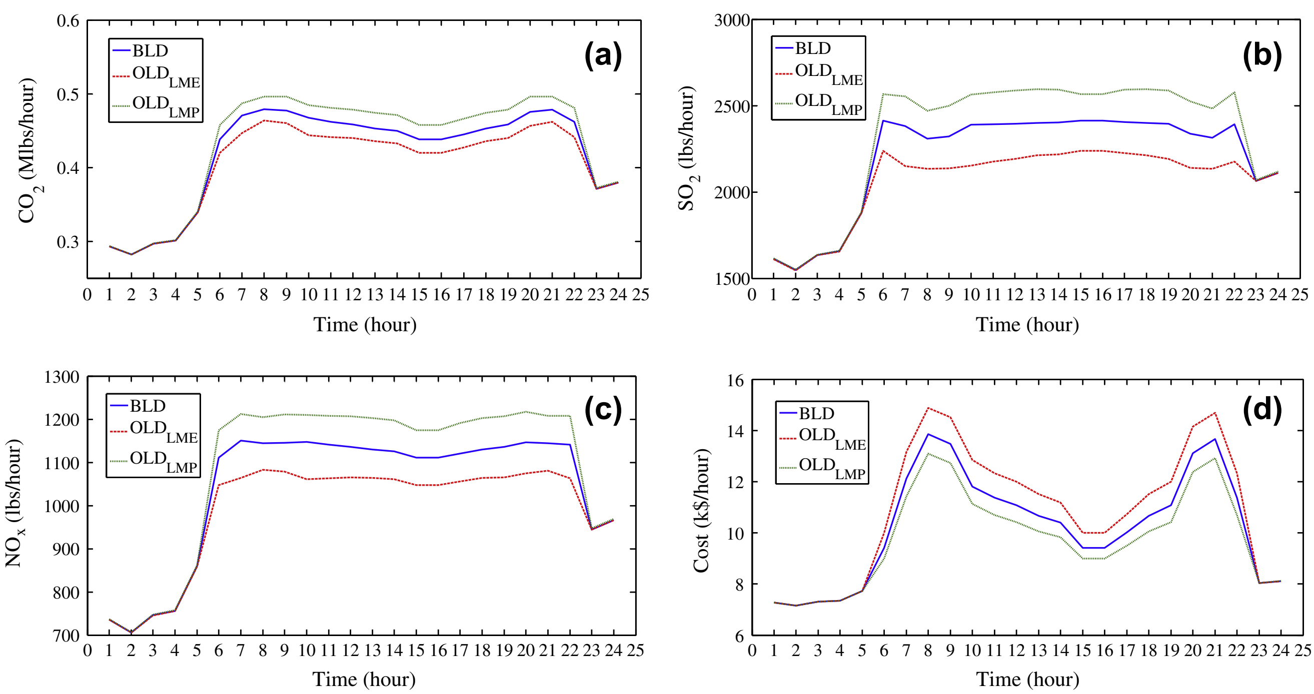

Fig. 5. Hourly CO_2 (a), SO_2 (b), and NO*x* (c) emissions and generation costs (d) during a typical summer day in the IEEE 14-bus system.

Table 7
Generation emissions and total costs for various costs of CO_2 (p_{r1}).

CO_2 cost ($/1000 Lbs)	Load distribution	CO_2 (MLbs)	SO_2 (Lbs)	NO*x* (Lbs)	Total cost ($1000)
0	BLD	10.06	52989	24984	245.86
	OLD_{LME}	9.75	49680	23797	260.75
	OLD_{LMP}	10.40	56048	26137	235.31
5	BLD	10.02	52610	24854	245.96
	OLD_{LME}	9.69	49152	23621	260.88
	OLD_{LMP}	10.36	55697	26005	235.3
20	BLD	9.90	51382	24428	247.52
	OLD_{LME}	9.56	47788	23158	262.45
	OLD_{LMP}	10.24	54654	25625	236.85
50	BLD	8.95	41159	20917	282.85
	OLD_{LME}	8.90	40560	20702	287.29
	OLD_{LMP}	8.95	41219	20934	282.36
100	BLD	8.39	34131	18601	318.07
	OLD_{LME}	8.38	34065	18571	317.91
	OLD_{LMP}	8.38	34070	18574	317.85

Table 8
The load demands, LMEs and LMPs in the different PJM control areas.

Area name/number	Load (MW)	LME (lbs/MW h)	LMP ($/MW h)
FE/202	11512.75	2165.52	37.39
AEP/205	23245.59	872.25	45.16
DLCO/215	2317.00	2267.04	33.22
CE/222	16588.89	1138.30	33.71
PJM/225	82.41	772.57	26.07
PENELEC/226	2876.26	196.38	37.76
METED/227	2786.61	2347.34	265.30
JCP&L/228	4129.06	777.51	31.23
PPL/229	7423.89	662.99	46.10
PECO/230	6884.07	966.18	299.56
PSE&G/231	7389.07	1952.43	53.81
BGE/232	6173.60	1391.15	51.08
PEPCO/233	5750.00	2080.02	52.05
AE/234	1965.00	690.29	557.50
DP&L/235	3425.00	1333.03	309.00
UGI/236	202.98	960.60	33.82
RECO/237	241.00	901.57	57.86

Table 9
Emissions of the PJM system under different spatial load distribution schemes.

Emissions (Lbs/h)	CO_2 ($\times 10^8$)	SO_2 ($\times 10^5$)	NOx ($\times 10^5$)
BLD	1.2808	6.3387	3.1867
OLD_{LME}	1.2247	6.0464	3.0395
OLD_{LMP}	1.2507	6.2224	3.1216

are controllable. As aforementioned, the LMPs can be obtained by solving OPF. Nonetheless, the LMEs were obtained by calculating the emission changes by increasing one percentage of loads for every control area, similar to the calculation of the bus LMEs in the IEEE 14-bus system.

The amount of CO_2, SO_2 and NOx emissions under different load distribution schemes are given in Table 9. Compared with the base load distribution, the changes of emissions of the two optimal load distributions (OLD_{LME} and OLD_{LMP}) are shown in Fig. 6. Since the price of nature gas is close to coal, or even lower for some generators, it is noted that both OLD_{LME} and OLD_{LMP} can decrease emissions. About 4.38% (OLD_{LME}) and 2.35% (OLD_{LMP}) emission reduction for CO_2, 4.64% (OLD_{LME}) and 1.84% (OLD_{LMP}) for SO_2, and 4.62% (OLD_{LME}) and 2.04% (OLD_{LMP}) for NOx have been achieved. The marginal generators in response to the two optimal load distributions are shown in Fig. 7. Note that the 'others' in the figure include hydroelectric, nuclear, wind and solar and other

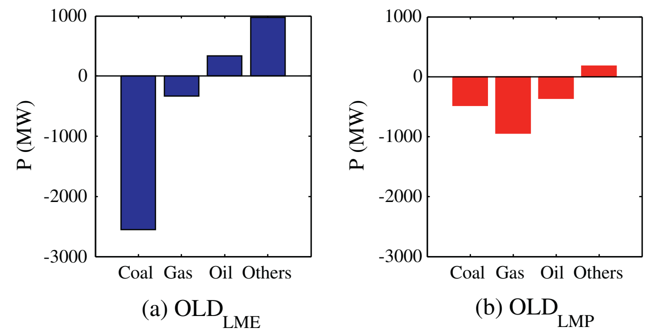

Fig. 7. The marginal generator units with respect to OLD_{LME} and OLD_{LMP} in the simulation study of PJM system.

low-emission generators. It can be clearly seen that the OLD_{LME} method is more effectively in reducing outputs of coal fired generators than the OLD_{LMP} method.

The results of the simulation studies of the PJM system demonstrates that optimizing the distribution of load based on LMEs is an effective approach for reducing emissions. Using the LME information, electricity users can participate in the process of pollutant reduction and control. Therefore, it is necessary for ISOs/RTOs to publish real time LME information (in addition to LMP information) to guide emission reduction at the demand side. This analysis also revealed that optimal load distribution based on LMPs may not always increase emissions. This is especially true if prices of fuels with relatively small emission factors (e.g., nature gas), are comparable to other fuels with relatively large emission factors (e.g., coal fuel). For example, in this scenario, low cost fuel-fired generators may consist of not only the high-emission coal generators but also low-emission natural gas generators. Nevertheless, the LME-based method was still found to be a more effective method of reducing emissions.

4. Discussions and conclusions

Based on the analysis and the simulation results presented, the effectiveness of the proposed optimal load management method depends on the following three critical conditions: (1) a diversity of generators which can provide different LMEs at load nodes within the electric power grid, (2) sufficient spatial flexibility of demand loads (temporal shifting was not described in this paper),

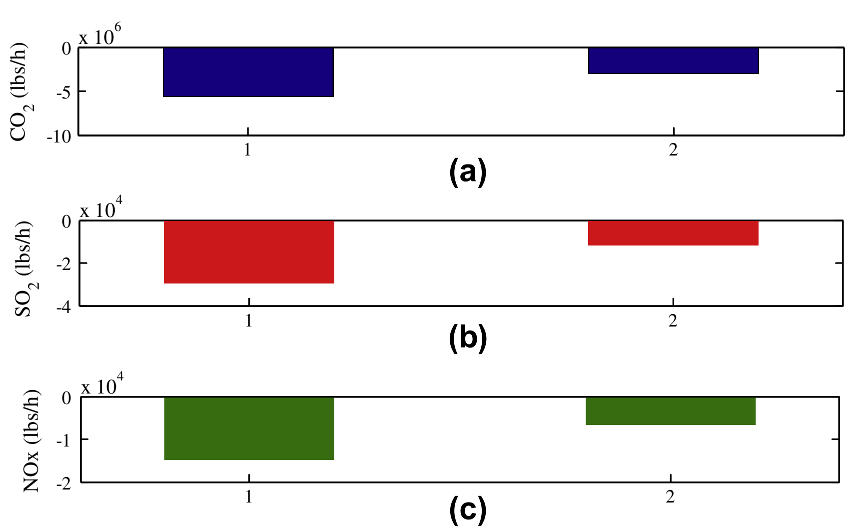

Fig. 6. The change of emissions with respect to (1) OLD_{LME} and (2) OLD_{LMP} in the PJM system.

and (3) CO_2 pricing in generator cost models. Condition 1 is satisfied in many regional power systems since a variety of generators are commonly found on the margin. Increasingly, controllable loads (such as intelligent appliances) continue to be incorporated into power systems. Moreover, for large (spatial) scale power consumers, such as water utilities, the spatial flexibility required to achieve emission reductions is feasible, satisfying condition 2. This condition could also be satisfied through an integrated network of smaller consumers (e.g., electric vehicles) in future Smart Grids. As a result, reducing emissions via the proposed alternative load distribution paradigm is feasible. For condition 3, a higher CO_2 price gives more weight to emission reductions in the generation power dispatch. However, in general, the generator cost will increase as a result. As such, incorporating CO_2 cost into consideration often aims to reduce CO_2 emissions from power plants while maintaining reasonable costs. The European Union (EU) implemented the European Union Greenhouse Gas Emission Trading Scheme (EU ETS) to help its members achieve their commitments under the Kyoto Protocol [27]. In the United States, state and local governments are leading efforts to develop policy approaches to GHG emissions management. Both CO_2 trading methods and upper emission restrictions [28,29] have been used to target GHG emissions reductions.

The focus of this paper is on emission reduction through spatial demand management. The paper discussed why the load distribution based on the LMPs, which represent the financial cost for the next incremental unit of load at a particular time and place, can lead to increases in emissions. It is necessary and important to introduce the new locational marginal emission index, LME, which directly reflects the marginal emissions due to the next incremental MWh used at a specific location. Using only the information of LME without comprising the confidentiality of power market operations, electricity users can efficiently decrease pollutant emissions by spatially redistributing their loads.

The LME-based load distribution is effective not only for a pure profit-driven power system without considering CO_2 cost, but also in the future systems where the cost of CO_2 emissions has been incorporated into generator cost models. As demonstrated in the IEEE 14 bus system, if CO_2 price is under \$5/klbs, the approximate cost of CO_2 trading at auction [26], LMEs can still be used for electricity users to shift load from one location to another, resulting in reductions of pollutant emissions. Moreover, although LMEs are calculated by simulating slight load increase for every load bus/area in this paper, in real systems, based on our previous work [24], LMEs can also be estimated from LMPs that are reported every 5 min. This can greatly facilitate the use of OLD_{LME} method as well.

Since LMEs do not release sensitive power market information, for environment protect and emission reduction, ISOs/RTOs should consider publishing real time LME information to customers, as currently being done for LMPs. Reducing emissions is not only the responsibility of power generators, but also electric energy consumers. With the information of LMEs, consumers can conveniently participate in the process of emission control. In the meanwhile, utilities can provide incentives in terms of LME values that can make consumers more willing to engage.

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