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Dynamic distributed generation dispatch strategy for lowering the cost of building energy

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HIGHLIGHTS

- Models of utility rate structures and building energy demand dynamics were built.
- Distributed generation dispatch strategies for minimizing cost were developed.
- Dispatch strategies are applied to dynamic energy demands of various buildings.
- Demand charge shifting and demand charge reduction dispatch strategies lowered cost.

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ABSTRACT

The practicality of any particular distributed generation installation depends upon its ability to reduce overall energy costs. A simple yet effective economic dispatch strategy with the goal to use distributed generation to minimize the cost of building energy is developed in this work. The strategy is designed to reduce the individual utility, operations and maintenance charges that increase the cost of energy. Various electric rate structures are modeled in detail and applied with the economic dispatch strategy to simulate meeting various measured building demand dynamics for heat and power. Using the economic dispatch strategy, various modes of operation, such as electric or thermal load following, peak shaving, peak shifting, or base-load operation are simulated. The economic dispatch strategy is compared to more traditional dispatch strategies to demonstrate its effectiveness in reducing total energy costs.

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1. Introduction

Distributed generation (DG) technologies that use natural gas are commercially available today, including small gas turbine (GT) systems, microturbine generators (MTG), and fuel cells (FC) [1]. Most of these systems produce electricity and high grade heat for combined heat and power (CHP) applications [2–4]. They are also capable of providing base load and load following electricity [5,6] as well as cooling through the use of absorption chillers [7–9]. They can also provide power quality support when used in conjunction with proper power electronics [10]. The economic

viability of DG depends strongly on how it is operated to meet building energy demands, i.e., depending upon the dispatch strategy [11].

Research has been accomplished to evaluate the economic impact of operating DG under basic operating strategies, such as base-loaded, following building electrical demand, or following building thermal demand. FC and MTG systems that follow building electrical demand have been studied, showing that both technologies are best suited for situations with large and consistent electrical and thermal demand as they take full advantage of all the FC and MTG products (electricity and heat) and that for situations without a consistent thermal load, it is better to employ a generator with higher electrical efficiency [12,13]. FC systems capable of electric demand tracking were also used to show the need for low DG capital cost and high building thermal demand for economic viability [14]. Base-load and electric demand following FC systems have been compared, showing that for all scenarios, a high electricity price relative to natural gas price and low capital cost is desired [15]. FC dispatch strategies have been further expanded to include base-load operation with and without electrical export, electrical load following, and electrical load following with

Abbreviations: BCTRD, Backup Generation Time Related Demand Charge; CCHP, Combined cooling, heat, and power; CHP, combined heat and power; CRC, Capacity Reservation Charge; DG, distributed generation; FC, fuel cell; GT, gas turbine; HR, heat recovery; MTG, microturbine generator; MUD, maximum utility demand; Non-TOU, non time of use; O&M, operations and maintenance; SCE, Southern California Edison; SCG, Southern California Gas Company; SFRD, Supplemental Facilities Related Demand Charge; STRD, Supplemental Time Related Demand Charge; TOU, time of use.

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grid support [4], showing that dispatch strategies used for grid support can be desirable. Electrical and thermal demand load following dispatch strategies have been compared for a combined cooling, heating, and power (CCHP) system, showing that the desirable dispatch strategy is dependent upon the specific energy load profile and DG equipment used [16]. CCHP systems designed to meet all building energy demands have been studied, showing that the attractiveness of using DG to meet building thermal demand varies depending upon the electric rate structure applied [17].

While base-load, electric load following, and thermal load following dispatch strategies are simple and easy to implement, other dispatch strategies have been developed to optimize DG operation. Such strategies may attempt to optimize numerous factors, such as the amount of primary energy consumed, CO₂ emissions, and operating costs [18], or focus on minimizing the cost of satisfying building energy demand [11].

Further optimization tools have been developed to establish optimal DG capacity for a particular building demand in addition to determining an optimal dispatch schedule. A mixed-integer, multi-objective optimization strategy has been developed and used to determine the range of technology combinations that would optimize the economic and environmental impact of DG [19]. A separate mixed-integer optimization strategy has been developed to minimize the total cost of purchasing and operating a DG system [20]. A strategy employing fuzzy linear programming was developed for the sizing of CHP and boiler systems [21]. Cost optimization has also been applied to residential CHP systems, which further showed the importance of electricity rate structures to DG economics [22]. “Foremost” in optimization tools is the Distributed Energy Resource Customer Adoption Model [20], which produces an optimal set of DG technologies and dispatch schedules for a given building energy demand [23–26].

This paper continues to examine the use of DG to reduce the cost of building energy. Highly detailed utility rate models, including electrical standby demand charges that change depending upon time of occurrence and magnitude of maximum utility demand, and a declining block natural gas rate structure, are developed. Building models are built using highly resolved (15-min) building electric demand and thermal demand data, allowing for concurrent evaluation of the combined heat and power dynamics. Finally, a novel economic dispatch strategy that dynamically minimizes the cost of building energy in real-time is developed and evaluated.

Only DG with the capability of supplying electricity and heat were considered as they involve the least amount of mechanical complexity, reducing investment risk. Electrical and natural gas utility models are based on Southern California Edison and Southern California Gas Company rate structures. The highly resolved building electrical and thermal demand was extracted from buildings located throughout Southern California. Simulated DG operation under the economic dispatch strategy for the building models was evaluated by comparing the energy cost savings produced with the economic dispatch strategy to savings produced under optimal and typical dispatch methods. In this paper, the dispatch strategy is developed, described and justified with limited application using four building dynamic demand profiles as examples. This dispatch strategy is used to help determine when investment in DG technology makes economic sense elsewhere [27].

2. Models

2.1. Electrical rate structure

Electric rate structures are typically broken down into fixed, energy (aka volumetric), and demand charges. The methods by which

these charges are calculated vary amongst utilities and rate structures (e.g., time of use, declining block, and fixed rate). As a result, the calculation of utility costs can vary drastically between utilities and depend strongly upon the specific tariffs that are applied. It is therefore important to capture the general characteristics of an electric rate structure and how it functions as a whole, as opposed to specific individual charges associated with a particular rate structure.

For example, some common rate structures can be broken down into non-time of use (non-TOU) and time of use (TOU) components. Individual charges can change between seasons, with the season that contains highest total utility demand typically comprising higher charges. Non-TOU energy charges consist of a flat rate that applies to all of the energy consumed by a customer while non-TOU demand charges are determined by the largest load recorded for that billing period. As for TOU energy charges, these typically depend upon the time of day in which the energy is consumed. TOU energy rates are generally highest during periods of high demand (“on-peak”), lower for periods of moderate demand (“mid-peak”), and lowest during periods of low demand (“off-peak”). Concerning the demand charges, TOU demand charges are typically determined by the largest demand that is recorded during a specific time period (i.e., time of day) during the billing period.

The electrical rate structures used in this work were based upon the structures used by Southern California Edison (SCE). SCE rate structures for commercial and industrial buildings are broken down by maximum yearly customer demand. Customers with loads greater than 20 kW are offered the choice between at least two different rate structure types: (1) TOU-A, which has larger energy charges than TOU-B; and (2) TOU-B, which has higher demand charges, but lower energy charges compared to TOU-A. Both rate structures contain TOU energy charges, and both TOU and non-TOU demand charges. SCE defines “summer” as June 1st through October 1st, and “winter” as all other times. During the summer, the on-peak hours are 12:00 p.m. to 6:00 p.m., the mid-peak hours from 8:00 a.m. to 12:00 p.m. and 6:00 p.m. to 11:00 p.m., and off-peak hours are all other hours. During the winter, on-peak hours do not exist, mid-peak hours are from 8:00 a.m. to 9:00 p.m., and off-peak hours are all other hours. Fig. 1 shows energy charges versus time of day for summer and winter season and Fig. 2 shows the percentage of a year for which each peak period is applicable. A non-TOU demand charge of \$11.88 per kW is applicable for all summer and winter months and is determined by the highest 15 min average demand in a month. During the summer, additional TOU demand charges exist for both on-peak and mid-peak, and are \$19.49 per kW and \$5.46 per kW respectively. These are

Fig. 1. Southern California Edison energy charges versus time of day for summer and winter seasons.

Fig. 2. Percentage of year for Southern California Edison Peak Periods.

determined by the highest 15 min average demand during the peak period in a month.

Customers with DG that meets all or part of the electrical demand are charged at standby rates. Common components of standby service are supplemental service (additional electricity used by the customer to meet their electrical demand), backup or standby service (electricity used during unscheduled DG outages), scheduled maintenance service (electricity used during scheduled DG downtime), and economic replacement power (electricity used when the cost of utility electricity is cheaper than DG electricity) [24]. These charges can be both time of use and non-time of use charges.

For SCE, standby rates only affect the application of demand charges. Customers with DG are charged the same energy rates as those without DG. SCE standby rates include a Capacity Reservation Charge (CRC), Supplemental Facilities Related Demand Charge (SFRD), Supplemental Time Related Demand Charge (STRD), and Backup Generation Time Related Demand Charge (BGTRD). The CRC is determined by the standby demand required of the system and is a fixed charge. The SFRD is a non-TOU demand charge that is applied when customer utility demand reaches a certain level specified by the utility through an interconnection agreement. Both the STRD and BGTRD are TOU demand charges. However, these charges are assessed at the time the maximum utility-supplied demand occurs. Thus, on-peak charges can be avoided if the maximum demand occurs during mid or off-peak periods. Finally, SCE customers with onsite generation are also subject to departing load energy charges. Departing load charges apply to any energy generated onsite. Standby and departing load rates are shown in Table 1.

While these rates are specific to SCE territory in 2012, it is important to realize that similar rate structures are applied by utilities around the world. Accurate analyses, however, require resolution of the particular manner in which the local utility

calculates fixed, energy, and demand charges for any particular DG installation. The analyses that are required to determine the economic viability of DG must take into account the complexities of the rate structures together with dynamic understanding of the end-use electricity and heat demand dynamics. These dynamics, coupled with the rate structure dynamics must also be understood for all seasons of the year and times of day. Only when these dynamics are appropriately accounted for can one thoroughly assess the viability of DG installations.

2.2. Natural gas rate structure

Natural gas utilities usually sell their gas in a block structure. These block structures can have a single price for all gas used or comprise up to a three tiered declining block structure, with gas typically becoming progressively cheaper as the customer reaches each new tier. The standard charge is in dollars per therm (unit of heat equivalent to 100,000 BTUs or 1.055×10^8 J). Southern California Gas Company (SCG) is a major provider of natural gas to most customers in southern California, providing a declining block structure for commercial and industrial users. Like many natural gas utilities, SCG's rates take into account the distribution and fuel costs. While distribution costs have been observed to be relatively stable for SCG, fuel costs regularly change depending upon the market price of natural gas. As a result, while natural gas rate structures are relatively simple, changes in fuel cost cause regular variations and introduce uncertainty in customer prices. Prior work has shown that fuel price has a large impact on distributed generation economics. However, due to increased reserves and production of natural gas, prices have been "depressed... to the lowest levels in a decade" [28], leading to price projections that remain low in the near future [29]. While energy price projections have been shown to be inaccurate [30], a distributed generation investment that pays back in a reasonable time period should reduce the risk of exposure to natural gas price volatility. As a result, the natural gas rate model used in the current work will follow SCG prices effective June 10th, 2012. This rate structure is as follows: \$0.81115/therm for the first 250 therms, \$0.56622/therm for the next 3917 therms, and \$0.402/therm for all subsequent therms.

2.3. Building models

Building models were developed using electrical load data showing energy consumption in 15 min increments acquired from 39 buildings throughout Southern California, 12 of which had corresponding thermal loads [31]. Four of these buildings, with disparate dynamic demand characteristics, are used to highlight the response of the economic dispatch strategy to different building energy demand. The characteristics of the building data are shown in Table 2, and a representative week from each of the four building loads is shown in Fig. 3.

Table 2 shows the average electrical load for the year, the average monthly electrical load factor (ratio of average electrical demand and maximum electrical demand), average monthly heating, the amount of time that both electrical and heating load are coincident, the annual electric utility bill and average electricity cost using the utility rate and costs presented in Section 2.1, and the annual natural gas utility bill and average natural gas cost using the utility rate and costs presented in Section 2.2. Fig. 3 shows the diurnal behavior of all building electrical demand, with the highest demand being experienced during on or mid peak periods. Loma Linda VA Hospital has the most consistent electrical load, as predicted by the high electrical load factor. The other three buildings have a lower electrical load factor, caused by the increased electrical demand during the middle of the day. The coincidence between electrical and thermal demand can also be

Table 1
Southern California Edison standby demand charges.

Name of charge	Type	Amount
<i>SCE standby charges</i>		
CRC (\$/onsite kW)	Fixed	\$5.15
SFRD (\$/kW)	Non-TOU demand	\$11.88
STRD – summer on-peak only (\$/kW)	TOU demand	\$19.49
BGTRD – summer on-peak only (\$/kW)	TOU demand	\$10.26
STRD – summer mid-peak only (\$/kW)	TOU demand	\$5.46
BGTRD – summer mid-peak only (\$/kW)	TOU demand	\$2.67
Departing load (\$/kW h)	Energy	\$0.01657

Table 2
Main characteristics of acquired building data.

Building name	Building type	Annual average electrical load (kW)	Average monthly electrical load factor	Average monthly heating demand (Therms)	Coincident electrical and heating demand (%)	Annual electric utility bill	Average cost of electricity (\$/kW h)	Annual natural gas utility bill	Average natural gas price (\$/Therm)
UCI Bren	College/University	206.7	0.607	1197.9	34.06	\$185,917	\$0.1040	\$9,419	\$0.5897
UCI Cal IT ²	College/University	420.8	0.621	4217.7	14.18	\$407,971	\$0.1097	\$29,203	\$0.5193
Patton State	Hospital	1679.4	0.651	41393.1	72.79	\$1,670,208	\$0.1066	\$157,895	\$0.3979
Loma Linda VA	Hospital	3089.4	0.789	66474.3	94.74	\$2,709,063	\$0.0926	\$328,076	\$0.3921

Fig. 3. Representative week of electrical and thermal demand for Loma Linda VA Hospital, Patton State Hospital, UCI Bren, and UCI Cal IT².

seen in Fig. 3, ranging from the large and consistent thermal demand for Loma Linda VA Hospital to the smaller and less consistent thermal demand for UCI Bren and UCI Cal IT².

Since the price of electricity changes between the winter and summer season, financial analysis using the building data could be improperly skewed; extra winter months would depress total potential savings while extra summer months would inflate potential savings if not allocated exactly as they are in the rate structures considered. For Southern California Edison, the proper seasonal ratio is 4 summer months to 8 winter months (e.g., see Fig. 2), or one summer month to every two winter months. If the acquired building data was not acquired for a complete year, then representative summer and winter months for the building must be added or subtracted in order to create the proper seasonal month ratio (corresponding to the rate structure).

3. Economic dispatch strategy

A cost minimizing dispatch strategy utilizes DG only when it reduces total energy costs. Energy costs are generally comprised of electricity demand and energy charges, and natural gas energy charges. The current economic dispatch strategy was therefore developed to utilize DG only when it minimizes these charges. Also, because demand charges are determined by the peak monthly average electrical load over 15 min increments, the dispatch strategy was designed to create an operating schedule resolved to that same time increment (15 min). The strategy was

also designed to block dispatch when the building load is less than the minimum power setting of the generator due to the fact that the generator cannot export electricity or operate below its minimum power setting. These aspects of the strategy will be discussed in the following sections.

This dispatch strategy performs four separate functions in order to minimize cost of electricity. The strategy (1) reduces demand charges by reducing maximum utility demand, (2) reduces demand charges by shifting maximum utility demand from on-peak to mid-peak or off-peak, (3) produces DG electrical energy when less expensive than utility provided electrical energy, and (4) produces DG electrical and thermal energy when less expensive than utility provided energy and natural gas. The parameters used in the economic dispatch strategy are shown in Table 3.

For illustrative purposes, the economic dispatch strategy will be used to control a generic DG with capacity of approximately half the average electrical demand of the corresponding building. The DG capacities are 1545 kW for Loma Linda VA Hospital, 850 kW for Patton State Hospital, 210 kW for UCI Cal IT², and 100 kW for UCI Bren. It is assumed that the generator has an electrical efficiency of 35%, O&M cost of \$0.02 per kW h, and can operate at any power setting between full capacity and half capacity.

3.1. Assumptions

The following assumptions were made in developing the economic dispatch strategy:

Table 3
Description of parameters used in the economic dispatch strategy.

Parameter	Description
$Cost_{kW\ h}$	Cost to produce an electric kW h using DG (\$/kW h)
η_e	Rated electrical efficiency of DG
η_t	Percent of fuel energy converted into useable heat
η_{max}	Maximum DG system efficiency achievable
ϵ_{HR}	Effectiveness of heat recovery from DG
ϵ_b	Thermal efficiency of boiler
$Cost_{NG}$	Cost of utility natural gas (\$/Therm)
$Cost_{O\&M}$	O&M cost of DG (\$/kW h)
$Cost_{HR\ O\&M}$	O&M cost of heat recovery (\$/kW h)
$Cost_{Boiler\ O\&M}$	O&M cost of boiler (\$/kW h)
C_1	Conversion from fuel unit of energy to kW h (kW h/Therm)

- Onsite generation is limited to producing real power and heat only. No ancillary services are considered (even though DG systems could provide such).
- Benefits associated with the increased reliability associated with grid-connected onsite generation are not included.
- Installed generation is always available for the time-period studied.
- Building electrical load is met at all times of the simulation period. Any load not met by distributed generation is met by purchasing electricity from the grid.
- Onsite generation is not allowed to produce more electricity than the building requires (power export constraint), consistent with most current utility rate structures.
- Building thermal load is met at all times. Any load not met by distributed generation is met by a natural gas boiler. Boiler efficiency is set at 90%.
- If more heat is produced than needed through onsite generation, excess heat is vented to the atmosphere.
- Electrical and thermal storage are not considered.
- Generator start-up and shut-down fuel costs are not considered.
- Maximum total (heat plus power) system efficiency is 80%.
- A conservative, but representative value for the heat recovery capabilities of a variety of DG technologies is applied (60% of the heat produced by onsite generation can be captured).
- The only economic benefit of investment in distributed generation is the reduction in electricity and natural gas bills.
- All fixed and variable operations and maintenance costs (O&M) associated with DG are lumped into a single variable O&M cost (including fixed O&M).
- Installation of DG switches the building electrical rate structure from the parent structure to the standby structure.

3.2. Economic dispatch strategy functions

3.2.1. Demand charge reduction

The dispatch strategy used in this study gives priority to minimizing demand and electrical energy charges as these costs can be significantly higher than the cost of natural gas. Because demand charges are determined by the highest 15 min average demand in a billing cycle (one month), spikes in the electrical load that have little to no impact on the energy charge can cause a large demand charge increase for typical utility standby rate structures. Thus, priority is given to minimizing demand charges in the first application of our dispatch strategy.

Since demand charges are determined by the highest 15 min average demand, or maximum utility demand (MUD), the simplest way to reduce these charges is to operate any onsite generation to keep the maximum utility demand from rising. For generators sized smaller than the maximum building load, the MUD can only be reduced from the maximum building load to the maximum building load minus the maximum output of the generator. With

perfect foreknowledge of a building electrical load, the generator can be turned on at precisely the right moments to ensure that demand charges are reduced as much as possible. Realistically; however, this is not possible and a more practical strategy must be adopted.

One such strategy is to set a demand threshold at the beginning of a month. This threshold could be set based upon historical data for the building in previous years for the same month. In the current case this threshold is set at the average daily maximum demand of the prior month minus the capacity of the installed generation. Whenever the building load increases beyond this threshold, the generator is dispatched in order to ensure that the MUD does not increase. If at any time during a single billing period the building demand surpasses the demand threshold plus the maximum output of the installed generation, then the MUD increases to fulfill the unmet building load. Since demand charges have increased with the new MUD, the prior demand threshold must be increased to become equal to the new MUD. For the remainder of that billing period, then, only DG dispatch that occurs when the building load surpasses the new demand threshold will reduce demand charges. This process repeats itself for all time periods till the end of the billing period (month), at which point the demand threshold is reset in preparation for the next month. This demand reduction strategy is performed for all TOU and non-TOU demand charges in the current demand charge reduction dispatch strategy.

This demand reduction strategy is illustrated for Loma Linda VA Hospital in Fig. 4 and UCI Bren in Fig. 5. Due to the relatively high electrical load factor, the DG must be operated constantly in order to ensure maximum demand reduction. As a result, the DG performs electrical demand tracking to ensure that the MUD does not increase. During Friday (Fri-12), the building electrical demand increases beyond the prior MUD and DG capacity, resulting in additional power demand and an increase in the MUD. The UCI Bren DG experiences significantly different operation despite using the same demand reduction strategy. Instead of tracking the electrical load, the DG is dispatched to shave the electrical demand peaks, resulting in operation only during the middle of the day.

3.2.2. Demand charge shifting

For the standby electrical rate structure outlined in Section 2.1, demand charges during the summer are determined by both when the MUD occurs and the magnitude of the MUD. Winter demand charges are non-TOU, with no value being added by shifting the MUD from mid-peak to off-peak times. Thus, winter months cannot reduce demand charges by shifting the charge from on- or mid-peak to off-peak times. For summer operation, on the other hand, demand charges can be reduced by ensuring that the MUD occurs away from on- and mid-peak times (called demand charge shifting herein). Demand charge shifting (to off- or mid-peak times) can be more important (cost-effective) than reducing the MUD magnitude. Demand shifting only occurs if the MUD otherwise occurs during on- or mid-peak times when no DG is installed. If the MUD when no DG is installed does not occur during on- or mid-peak times, demand charge shifting cannot be performed and demand reduction is accomplished as outlined above.

If the MUD occurs during on- or mid-peak, then demand shifting is performed by allowing the utility demand to surpass the prior MUD during lower cost periods through appropriate DG dispatch. On-peak demand shifting translates into letting mid- or off-peak load increase while mid-peak demand shifting translates into letting off-peak load increase. While demand shifting consists of allowing the MUD to increase away from on- or mid-peak, demand reduction still occurs during the process of demand shifting if possible. For generators with a minimum dispatch constraint (e.g., a microturbine that must operate close to or at full power due to

Fig. 4. Demand reduction dispatch for Loma Linda VA Hospital during a winter month.

Fig. 5. Demand reduction dispatch for UCI Bren during a summer month.

emissions constraints [1]), the generator is dispatched only if the building load is greater than the prior MUD by the minimum generator dispatch power. Otherwise, the generator is left off. Performing demand shifting ensures that not only is the MUD reduced, but that the demand charge rates are also minimized. While demand shifting is being performed, dispatch aimed at reducing electrical energy and natural gas energy charges is blocked.

This dispatch strategy that includes both demand charge reduction and demand shifting is illustrated in Fig. 6 for summer operation at Patton State Hospital. During Thursday (Thu-04) and Friday (Fri-05), the DG only operates whenever the building load

surpasses the MUD, ensuring that demand charges do not increase. Despite succeeding in stopping the MUD from increasing, the MUD was established during on-peak. As a result, the MUD is allowed to increase during Saturday (Sat-06), shifting the time of the MUD from on-peak to off-peak. While the MUD increases, the shift from on-peak to off-peak demand charges reduces overall costs. The demand threshold increases with the MUD; thus for all times in the billing period following Saturday (Sat-06), the generator is only dispatched when the building load surpasses the new increased demand threshold. This ensures that demand charges do not increase and are not shifting back from off-peak to mid- or on-peak times.

Fig. 6. Demand reduction and peak shifting strategy for Patton State Hospital during a summer month.

3.2.3. Electrical energy replacement dispatch

Electrical energy replacement dispatch is available when utility purchased electrical energy is more expensive than an equivalent amount of fuel energy plus O&M required to dispatch the DG system costs. As a result, if demand shifting is not occurring, the electrical energy replacement dispatch strategy dispatches local generation if the cost to operate the DG is less than that of purchasing electricity from the grid. With the cost of onsite generation being created by the fuel required to operate the generator and O&M, the cost of a kW h is:

$$\text{Cost}_{\text{kWh}} = \frac{C_1 * \text{Cost}_{\text{NG}}}{\eta_{\text{elec}}} + \text{Cost}_{\text{O\&M}} \quad (1)$$

If the Cost_{kWh} is less than the cost of grid electricity and demand shifting is not occurring, then the generator is operated for electrical energy replacement.

Assuming an electrical efficiency of 35% and an O&M cost of \$0.02 per kW h and Tier 3 natural gas cost, electricity can be produced at a lower cost than what is available from the electric utility during all on and mid peak periods, regardless of season. During off-peak, however, the utility provides less expensive electrical energy. This effect on electrical energy replacement dispatch is seen in Fig. 7, which shows DG operation at UCI Cal IT² during a winter month. During the middle of the day (mid-peak), the DG produces as much electricity as possible, providing base-load power for the entire mid-peak period. As soon as off-peak is reached, the utility provides less expensive energy, and the DG is turned off.

3.2.4. Electrical and thermal energy replacement dispatch

Captured waste heat produces heating that would have otherwise had to have been provided by firing a boiler using additional natural gas. If both demand reduction and electrical energy replacement do not reduce energy costs and a building thermal load exists, the addition of captured waste heat has the potential to cause onsite generation to be less expensive than the otherwise necessary grid electricity and fuel purchases required to meet both the building electrical and thermal loads. The cost of onsite generation is similar to Eq. (1) with the addition of a term that includes savings due to waste heat recovery:

$$\text{Cost}_{\text{kWh}} = \frac{C_1 * \text{Cost}_{\text{NG}}}{\eta_e} \left[1 - \frac{\eta_t}{\epsilon_b} \right] + \text{Cost}_{\text{O\&M}} + \frac{\eta_t}{\eta_e} \frac{1}{\epsilon_b} (\text{Cost}_{\text{HR O\&M}} - \text{Cost}_{\text{Boiler O\&M}}) \quad (2)$$

Fig. 7. Electrical energy replacement dispatch strategy for UCI Cal IT² during a winter month.

The thermal efficiency η_t is determined by the following equation:

$$\eta_t = (\eta_{\text{max}} - \eta_e) \epsilon_{\text{hr}} \quad (3)$$

Eq. (2) calculates the cost to produce one kW h of electrical energy while also taking into account the avoided natural gas purchases that would otherwise be necessary for heating. If Cost_{kWh} is less than the cost of grid electricity, the generator operation could potentially reduce energy costs. The generator is set to produce enough electricity so that all of the available waste heat is utilized. If this power setting is higher than the capacity of the generator, then the power setting is set to the maximum capacity. If the power setting is lower than the minimum allowable power of the generator, then the cost of producing the additional electricity is calculated using Eq. (1). The cost of producing the electricity onsite with partial heat recovery is then compared to the cost of purchasing the electricity and natural gas from a utility, with the less expensive option being selected.

Assuming an electrical efficiency of 35% and an O&M cost of \$0.02 per kW h and Tier 3 natural gas cost, heat recovery allows for DG to produce electrical and thermal energy at a lower cost than purchasing the equivalent amount of energy from the electric and natural gas utilities during all off-peak periods. This effect on electrical and thermal energy dispatch is seen in Fig. 8, which shows both electrical energy replacement and electrical and thermal energy replacement for Loma Linda VA Hospital during a summer month. During on and mid-peak periods, it is less expensive to produce electrical energy using DG than to purchase it from the utility, allowing for energy replacement to occur regardless of heat recovery. However, during off-peak period, heat recovery must occur if any type of energy replacement is to occur. As a result, the DG electrical output is reduced so that the heat produced is utilized and not wasted, and thermal load following is performed. If the thermal demand is sufficiently large, base-load operation will occur, but is not seen in this example.

Even for buildings that have large thermal demand, coincidence between electrical and thermal demand is required for consistent operation. UCI Cal IT² has low coincidence due to a sporadic thermal demand. As a result, any DG operation due to electrical and thermal energy replacement dispatch is also sporadic, as seen in Fig. 9. While DG operation is consistent during periods where heat recovery is not needed for energy replacement, the lack of coincidence results in numerous DG starts and stops during periods where heat recovery is needed. The viability of this type of DG operation is discussed further in Section 5.

4. Optimal dispatch design for comparison

The goal of the dispatch strategy presented in Section 3 is to reduce the cost of building energy using utility and DG energy sources. As stated in the introduction, many other optimization efforts have been presented [11,12,18–26]. Many of these optimization methods determine the DG capacity and dispatch schedule that minimize total cost of energy. Two fundamental differences between the proposed economic dispatch strategy and optimization methods is that the resulting dispatch from the proposed strategy may not be optimal, but the proposed strategy does not need prior knowledge of building energy demand to minimize cost. In addition, these optimization strategies can be paired with other methods, such as model predictive control, to dynamically minimize the cost of building energy. The proposed economic dispatch strategy cannot financially outperform the powerful optimization methods developed in prior work. However, if the economic dispatch strategy can produce energy cost savings comparable to sav-

Fig. 8. Electrical and thermal energy replacement for Loma Linda VA Hospital during a summer month.

Fig. 9. Electrical and thermal energy replacement for UCI Cal IT² Hospital during a winter month.

ings produced through optimization methods, the benefit of the economic dispatch strategy is increased due to reduced computational requirements needed to operate the economic dispatch strategy.

In order to validate that the proposed dispatch strategy minimizes energy costs, the strategy must be compared to the results of an optimal dispatch strategy similar to what is found in the current literature. In order to accomplish this, a linear program was developed using the terms found in the proposed dispatch strategy but formulated to produce an optimal solution. The parameters listed in Table 3 are used to describe DG performance and operational characteristics. Additional sets, parameters, and variables used in the linear program are listed in Table 4. Since the proposed dispatch strategy does not determine optimal DG capacity, the capital cost terms used to determine DG type and capacity used in many optimization strategies is omitted. The objective function minimizes the total operational cost of meeting required building energy through Eq. (4). Eq. (4) captures the cost of grid energy charges, demand charges, the value of shifting maximum utility demand towards off-peak during summer months, the cost of fuel

and O&M for DG operation, the cost of fuel for boiler operation, and the cost of O&M for heat recovery operation. The $Cost_{grid,t}$ term is set to the energy charge for the applicable peak period as shown in Fig. 1, the demand charge values are set to the charges described in Section 2.1 and the $Cost_{NG,n}$ term is set to the average natural gas cost for the specific building during the applicable month.

$$\begin{aligned}
 & \sum_t Cost_{grid,t} * E_{grid,t} + \sum_n DC_{nonTOU,n} * P_{max,n} + \sum_m DC_{ON,n} \\
 & * P_{maxON,m} + \sum_m DC_{MID,n} * P_{maxMID,m} + \sum_m DC_{Shift,m} * \Delta_m \\
 & + \sum_t \left[\frac{C_1 Cost_{NG,n}}{\eta_e} + Cost_{O\&M} \right] E_{DG,t} \\
 & + \sum_t \left[\frac{C_1 Cost_{NG,t}}{\varepsilon_b} + Cost_{Boiler\ O\&M} \right] E_{Boiler,t} + \sum_t Cost_{HR\ O\&M} \\
 & * E_{HR,t}
 \end{aligned} \quad (4)$$

The constraints shown in Eqs. (5) and (6) ensure that all building electrical and thermal demand is met.

Table 4

Description of additional parameters used in optimal dispatch formulation.

Sets	Description
$n \in N$	Set of all months
$m \in M$	Set of all months ($M \subset N$)
$t \in T_n$	Set of all 15 min time increments in month n
$o \in O_m$	Set of all 15 min time increments during on-peak in summer month m ($O \subset T$)
$p \in P_m$	Set of all 15 min time increments during mid-peak in summer month m ($P \subset T$)
Building parameters	
$E_{\text{Bldg Elec},t}$	Building electrical energy demand at time t
$E_{\text{Bldg Heat},t}$	Building thermal energy demand at time t
Utility cost parameters	
Cost_{NG}	Utility natural gas charge for natural gas purchased (\$/Therm)
$\text{Cost}_{\text{grid},t}$	Utility energy charge for electricity purchased during time t (\$/kW h)
$\text{DC}_{\text{nonTOU},n}$	Utility non time of use demand charge for maximum demand during month n (\$/kW)
$\text{DC}_{\text{ON},m}$	Utility on-peak demand charge for maximum on-peak demand during summer month m (\$/kW)
$\text{DC}_{\text{MID},m}$	Utility on-peak demand charge for maximum mid-peak demand during summer month m (\$/kW)
$\text{DC}_{\text{Shift},m}$	Value of demand shift during summer month m (\$/kW)
Utility variables	
$E_{\text{grid},t}$	Amount of utility electrical energy purchased during time t (kW h)
$P_{\text{max},n}$	Maximum utility demand during month n (kW)
$P_{\text{maxON},m}$	Maximum on-peak utility demand during summer month m (kW)
$P_{\text{maxMID},m}$	Maximum mid-peak utility demand during summer month m (kW)
Δ_m	Difference between on-peak and non time of use maximum demand during summer month m (kW)
α	Minimum allowed value of Δ_m (kW)
DG parameters	
$P_{\text{DG Capacity}}$	Power capacity of installed DG (kW)
DG, Heat recovery, and boiler variables	
$E_{\text{DG},t}$	Electrical energy produced by DG at time t (kW h)
$E_{\text{HR},t}$	Thermal energy produced by heat recovery at time t (kW h)
$E_{\text{boiler},t}$	Thermal energy produced by boiler at time t (kW h)

$$E_{\text{grid},t} + E_{\text{DG},t} = E_{\text{Bldg Elec}, t} \quad (5)$$

$$E_{\text{Boiler},t} + E_{\text{HR},t} = E_{\text{Bldg Heat},t} \quad (6)$$

Eq. (7) determines the maximum utility demand for each month. Eqs. (8) and (9) determine the maximum utility demand for on and mid-peak during summer months. The factor of four is used in Eqs. (7)–(9) to convert from the energy used in a 15 min period to average power demand.

$$4E_{\text{grid},t} \leq P_{\text{max},n} \quad \forall n \in N, t \in T_n \quad (7)$$

$$4E_{\text{grid},o} \leq P_{\text{maxON},m} \quad \forall m \in M, o \in O_m \quad (8)$$

$$4E_{\text{grid},p} \leq P_{\text{maxMID},m} \quad \forall m \in M, p \in P_m \quad (9)$$

Eq. (10) limits the DG output to the installed capacity. Eq. (11) limits the heat recovery output to the heat produced from DG operation.

$$4 * E_{\text{DG},t} \leq P_{\text{DG Capacity}} \quad (10)$$

$$E_{\text{HR},t} \geq E_{\text{DG},t} \frac{\eta_t}{\eta_e} \quad (11)$$

Eq. (12) ensures that the demand shifting component of the objective function is determined by the difference between the maximum on-peak and maximum monthly utility demand. Whenever the maximum utility demand has been shifted away from on-peak, Δ_m will turn negative and reduce the objective function.

$$\Delta_m = P_{\text{maxON},m} - P_{\text{max},m} \quad (12)$$

When Eq. (12), is omitted from the constraints, the on- and mid-peak utility demand were reduced by the DG capacity for the four buildings presented in Section 2.3. In addition, the maximum summer on-peak demand is greater than all mid-peak demand for the four buildings. As a result, the constraint established by Eq. (9) indirectly ensures that the mid-peak maximum is lower than the on-peak maximum demand. Coupled with Eq. (12), maximum utility

demand is shifted from on- or mid-peak to off peak. As a result, an additional cost term and constraint that considers the value of shifting maximum demand from mid- to off-peak is not necessary. However, if the building electrical demand were to change and a summer maximum utility demand occurred during mid-peak prior to DG installation, an additional constraint similar to Eq. (12) would be required to relate maximum mid-peak demand to maximum monthly demand.

All variables are nonnegative, except for Δ_m , which follows the constraint below.

$$\Delta_m \geq \alpha \quad (13)$$

The value α is set to a slightly negative number so that the linear program shifts demand to off-peak but does not needlessly increase off-peak demand. α is set to -1 kW for all examples.

5. Comparison to other typical dispatch strategies

The economic dispatch strategy must be compared to other potential strategies in order to verify that the proposed strategy is practical and outperforms all other viable options. The practicality of the strategy depends on the DG characteristics and the building electrical and thermal demand, either of which may lead to deviations from the economic dispatch strategy. For example, the electrical and thermal energy dispatch of the DG system illustrated in Fig. 9 during off peak periods is undesirable for virtually all DG technologies and would not be followed, while the electrical energy replacement during the on and mid peak periods is possible for many DG technologies. The financial performance of the economic dispatch strategy should be compared to other potential dispatch strategies as a matter of due diligence prior to any DG investment.

The economic dispatch strategy is compared against a base-load strategy where the generator is set to full power except for whenever building electrical demand is lower than the maximum DG capacity. If this occurs, the DG systems track the electrical demand

to ensure no electrical export occurs. This dispatch strategy is simple, but not unreasonable. The base-load strategy will result in maximum demand reduction and the DG systems produce electrical energy at a lower cost than what is available from the electric utility during all on and mid peak periods if Tier 3 natural gas prices are available. Under the economic dispatch strategy, base-load operation is observed during these peak periods. In addition, the DG systems can also provide electrical and thermal energy at a lower cost than the utilities during all off peak periods if a large portion of the generated heat is utilized. While the base-loaded DG systems are capable of reducing many energy costs, not all potential savings can be realized; thermal load following, peak shaving, and peak shifting do not occur as they do under the economic dispatch strategy.

The economic dispatch strategy is also compared to the optimal dispatch results as well as the simple dispatch strategy (base-load dispatch). The three dispatch strategies are then used to operate DG for the four building loads described in Section 2.3. Heat recovery and boiler O&M costs are assumed to be equivalent and do not affect the optimization or economic dispatch strategy. Fig. 10 shows for the four buildings the annual operating cost of energy per kW of average building electrical demand. The average building electrical demand is used to normalize the costs to a comparable scale for the four buildings due to their differences in size and cost of energy. For the scenario where no DG is installed, only the electrical utility and natural gas utility costs are considered. For base-load, economic, and optimal dispatch strategies, electrical utility, natural gas utility, and DG O&M costs are considered. Fig. 10 shows that while the base-load dispatch strategy reduces the cost of building energy significantly, lowest cost is achieved by the economic and optimal dispatch strategies. Table 5 shows the total cost reduction for the four buildings when using the three dispatch strategies. In addition, the relative sizes of the O&M costs for the different buildings show that the reduced cost under the economic and optimal dispatch strategy is achieved despite less DG operation. While the DG systems are dispatched for shorter periods of time under the economic and optimal dispatch strategies, operation only occurs when energy cost can potentially be reduced. The optimal dispatch strategy reduces costs further than the economic dispatch strategy. However, a significant portion of savings are realized under the proposed strategy. For Loma

Table 5

Total cost reduction for the four buildings tested using the base-load, economic, and optimal dispatch strategy.

Building	Base-load (%)	Economic dispatch (%)	Optimal dispatch (%)
Loma Linda VA Hospital	29.5	31.3	32.2
Patton State Hospital	24.7	31.1	32.8
UCI Bren	17.6	22.8	23.2
UCI Cal IT ²	22.4	29.9	30.9

Linda VA Hospital, Patton State Hospital, UCI Bren, and UCI Cal IT², 97.1%, 94.9%, 98.2%, and 96.8% of optimal savings are realized under the economic dispatch strategy for the buildings respectively.

Fig. 10 also allows insight into how the different DG dispatch strategies achieve their savings by separating out the utility electrical energy charges and demand charges. The detailed rate structure model allows these demand charges to be resolved, and thus show how the different dispatch strategies reduce the demand charges. In Fig. 10, the demand charges for each building are a significant portion of the overall energy costs when no DG is used, allowing for large savings to be realized from demand reduction. For each building, the demand charges are reduced significantly with the most reduction occurring using the economic and optimal dispatch strategy due to active demand shifting. Although the utility electric energy charges still represent a significant cost when DG is used, and the base-load dispatch strategy reduces the utility electric energy charges more than the economic or optimal dispatch strategy (as expected), this does not result in overall better savings; base-load operation does not perform demand shifting and does not reduce the DG power when grid electricity is the least expensive option.

Further insight into the dispatch strategies can be made using the capability of the detailed rate structure model to resolve all the different electric utility charges. Fig. 11 shows the breakdown of the electric utility energy charges into on-, mid-, and off-peak. The on-peak charges are reduced equivalently with both dispatch strategies because for all dispatch strategies the DG will be on during on-peak. The base-load dispatch strategy reduces the mid- and off-peak charges more because the economic dispatch strategy

Fig. 10. Annual operating cost of building energy per kW of average building electrical demand for Loma Linda VA Hospital, Patton State Hospital, UCI Bren, and UCI Cal IT² for no DG installed on-site, DG operated using base-load, economic, and optimal dispatch strategy.

may or may not run during these periods depending on what needs to be done for demand shifting or reduction. Under the economic and optimal dispatch strategies, DG operation is similar during all peak periods for UCI Bren and UCI Cal IT². DG operation is also similar for Loma Linda VA Hospital and Patton State Hospital during all on-peak and mid-peak, but off-peak operation differs for these two buildings. Due to a large and consistent thermal demand, both buildings have access to the low cost natural gas and a use for heat produced from DG. However, during off-peak, savings from using DG to replace electrical and thermal energy are small due to a low cost of utility electrical energy. Value still exists in reducing demand during off-peak. However, choosing to use utility energy or DG energy to meet energy demand can have a small impact on total cost; DG operation is not always the same between the economic and optimal dispatch strategy during off-peak, but the difference in total savings between the two strategies is small regardless.

No discussion regarding DG economics is complete without including DG capital cost. Without the inclusion of capital cost, the potential savings shown in Fig. 10 are exaggerated and may disappear depending upon the DG investment cost. The inclusion of capital cost is usually coupled with the economic evaluation of any DG project through the use of financial metrics, such as investment payback length, internal rate of return, or net present value, to judge the investments economic potential [32]. Due to space limitations, this paper focuses only upon operating costs for a limited set of building models. The full economic evaluation (including capital costs) using the current economic dispatch strategy and an extensive set of building models is presented elsewhere [27].

Nonetheless, to provide the reader with a sense for capital costs that the current dispatch strategy could accommodate, the DG capital cost limits for desired economic performance can be determined from Fig. 10. Assuming that the DG systems are purchased

Fig. 11. Annual electric utility energy charges per kW of average building electrical demand for Loma Linda VA Hospital, Patton State Hospital, UCI Bren, and UCI Cal IT² for no DG installed on-site, DG operated using base-load, economic, and optimal dispatch strategies.

Fig. 12. Break even capital cost per kW of installed DG per building for the base-load, economic, and optimal dispatch strategies assuming 100% financing, a debt term of 10 years, and interest rate of 8% annually.

using 100% financing, the approximate DG capital cost can be found using

$$\text{Monthly Debt Payment} = \frac{\text{Principal} * i}{1 - (1 + i)^{-n}} \quad (14)$$

where i is the interest rate and n is the debt term. Assuming an annual interest rate of eight percent, a debt term of 10 years, and no savings or losses are realized (the investment is breaking even), the allowable capital cost can be determined for the economic dispatch and base-load strategy using Eq. (14), as seen in Fig. 12. For all four buildings, DG operating under the economic dispatch strategy can absorb a higher capital cost and continue to maintain similar economic performance than DG operated under the base-load strategy. Obviously, DG operated under the optimal dispatch strategy can absorb the highest capital cost. However, if the economic dispatch strategy behaves similarly to the optimal strategy, the allowable capital cost for the economic dispatch strategy approaches the cost allowed by the optimal strategy.

Fig. 12 also shows that, versus base-load operation, better economic performance can be realized under the economic dispatch strategy in addition to the possibility of investing in DG technology that has desirable performance but high capital cost. As requirements for profitability increase, debt financing, or amount of initial investment change, the allowable capital cost will need to decrease in order to produce savings. If a cost minimizing dispatch strategy, such as the economic dispatch strategy presented, is employed, economic performance of DG systems can be improved, and the maximum financial value of DG can be realized.

6. Conclusions

Detailed models that determine utility energy costs, including standby charges for DG, and highly resolved building electrical and thermal demand are developed. A simple yet effective economic dispatch strategy is designed and implemented using the utility rate and building models for a generic DG installation. The main findings of this analysis are:

- While the economic dispatch strategy cannot outperform an optimal dispatch strategy, a significant portion (>90%) of the savings produced through optimal methods can be realized using the economic dispatch strategy. The economic dispatch strategy accomplishes these cost savings without prior knowledge of the building demand, which is required by the optimal dispatch strategy.
- Larger capital cost can be absorbed by DG operating under an optimal dispatch, however, the proposed economic dispatch strategy can absorb a capital cost that is nearly the same. This can allow for DG with desirable performance characteristics (i.e. high electrical efficiency) but high capital cost to still perform well economically with a simple yet effective dispatch algorithm.
- Cost minimizing dispatch is determined by the building load and characteristics of installed DG. Economic dispatch can lead to electric or thermal load following, peak shaving, peak shifting, base-load operation, or no operation.
- The economic dispatch strategy can outperform base-load dispatch strategies due to the capability to adjust DG operation to ensure that the building energy demand is met in an economically efficient manner. By allowing for DG dispatch decisions to be made solely on economic terms, larger savings can be produced.

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