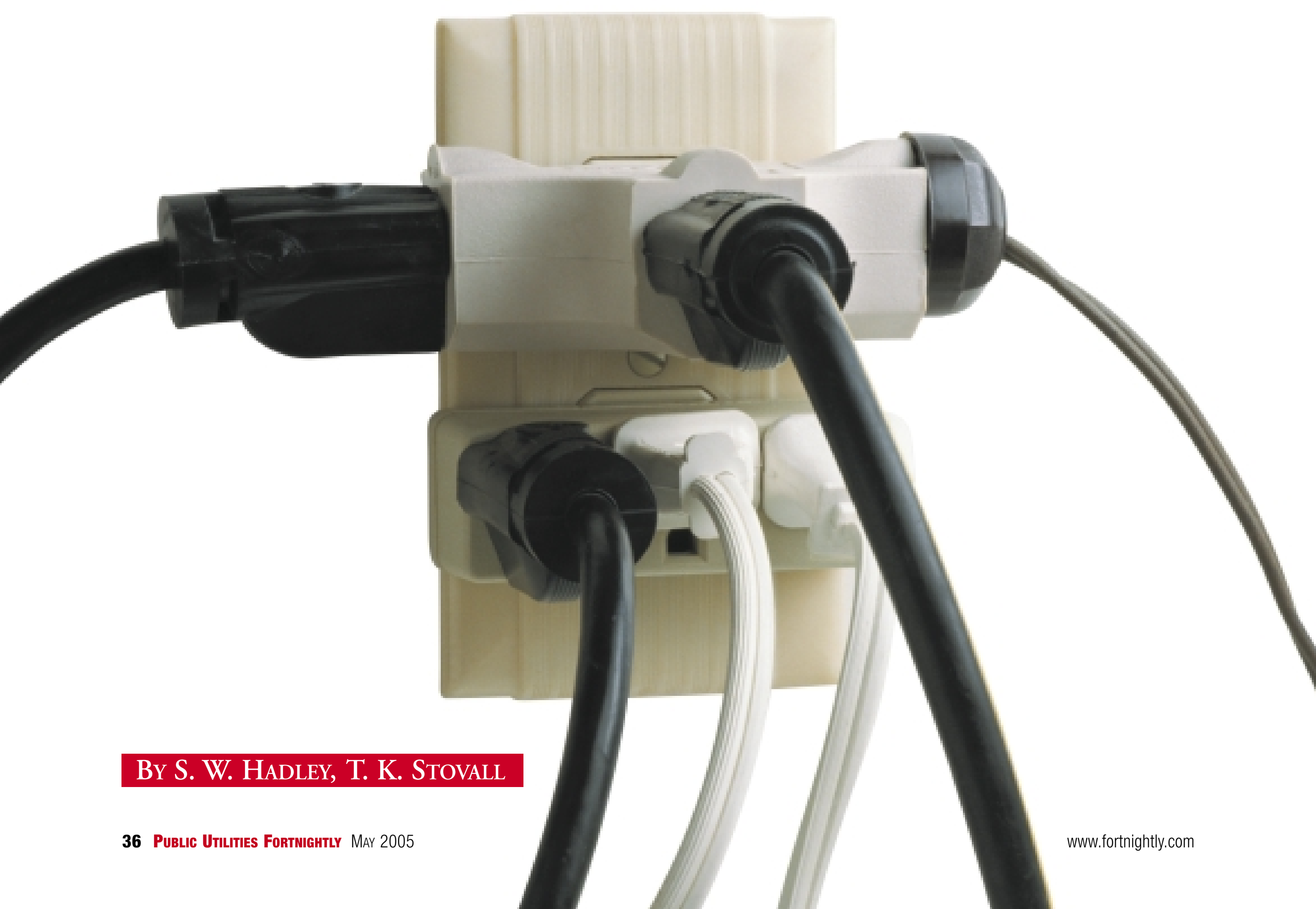
DER:

Hastening Genco Obsolescence?

This final installment of Oak Ridge National Laboratory's series on distributed energy resources investigates efficiency, the environment, and generation displacement.



By S. W. Hadley, T. K. Stovall

Distributed energy resources (DER) have been touted as a clean, efficient way to generate electricity at end-use sites, potentially allowing the exhaust heat to be put to good use as well. However, in a time when new combined-cycle (CC) plants are being mothballed and older plants retired because of high gas prices and lack of demand, does it make environmental sense to use DER? Does DER displace other, cleaner generation technologies, or does it compete against older, dirtier power plants instead?

If DER systems are built, then older generating plants may be retired sooner, removing some of the worst polluters. Or it may be that DER does not directly compete against either new or old plants at the capacity planning decision-maker level. If so, increased DER simply raises reserve margins and reduces the amount of time that various central plants operate, with a mixture of results.

A critical question for policymakers is whether DER results in more pollution or less. The key factor in answering the question is the type of power production displaced if DER is added. For every kilowatt-hour produced by DER, a kilowatt-hour (or more with losses) is not produced at other plants. Production from different plants will be reduced at different times. If enough DER capacity is created, some power plants will be retired or some plants will not be built, so not only their production but their capacity also will be displaced. The change in capacity will affect operating schedules at other plants. The complex interactions within the market over time make it difficult to claim that DER displaces any single other capacity type. Of course, the DER characteristics are also an important factor in determining the net impact of any displacement.

To address the multifaceted problem of DER displacement, the Department of Energy Distributed Energy Program recently asked Oak Ridge National Laboratory to examine the changes in an electric system resulting from the introduction of a relatively large amount of DER. We chose to model the Mid-Atlantic Area Council (MAAC), one of the reliability councils in the North American Electric Reliability Council. We used the Oak Ridge Competitive Electricity Dispatch model to simulate the addition of 2,000 MW of DER into the region with projected 2006 demands. We could then see how other plants changed their operations, and the consequent changes in energy use and air emissions.

A matrix of cases was considered. Two simple DER scenarios were evaluated: DER operating all the time (baseload) and DER operating only during weekdays from 8 a.m. to 8 p.m. For both scenarios, DER was considered with and without the useful capture of waste heat (combined heat and power, or CHP). We created three options: (1) no other change occurring in the rest of the system's capacity; (2) an equivalent amount of new gas-fired CC capacity not being built; and (3) the oldest and least-economical existing capacity retiring. A variant of option (2) was added to more appropriately match the reduction in CC capacity to the actual reduction in peak load for weekday DER operation. Because of the recent volatility in gas prices, we also conducted an analysis of sensitivity to fuel price. The DER emissions were based on a low-NO_x gas-fired combustion turbine.

FIGURE 1 **POWER PLANTS DISPATCHED TO MEET THE PEAK SEASON LOAD DURATION CURVE**

(Plants touching the top of the curve are "on the margin")

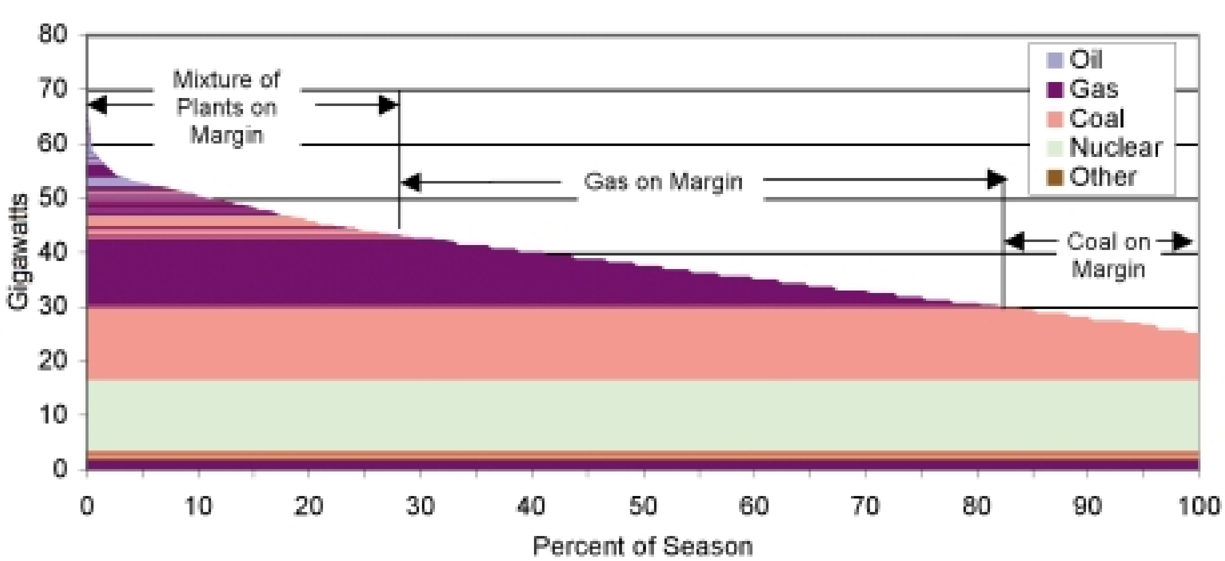
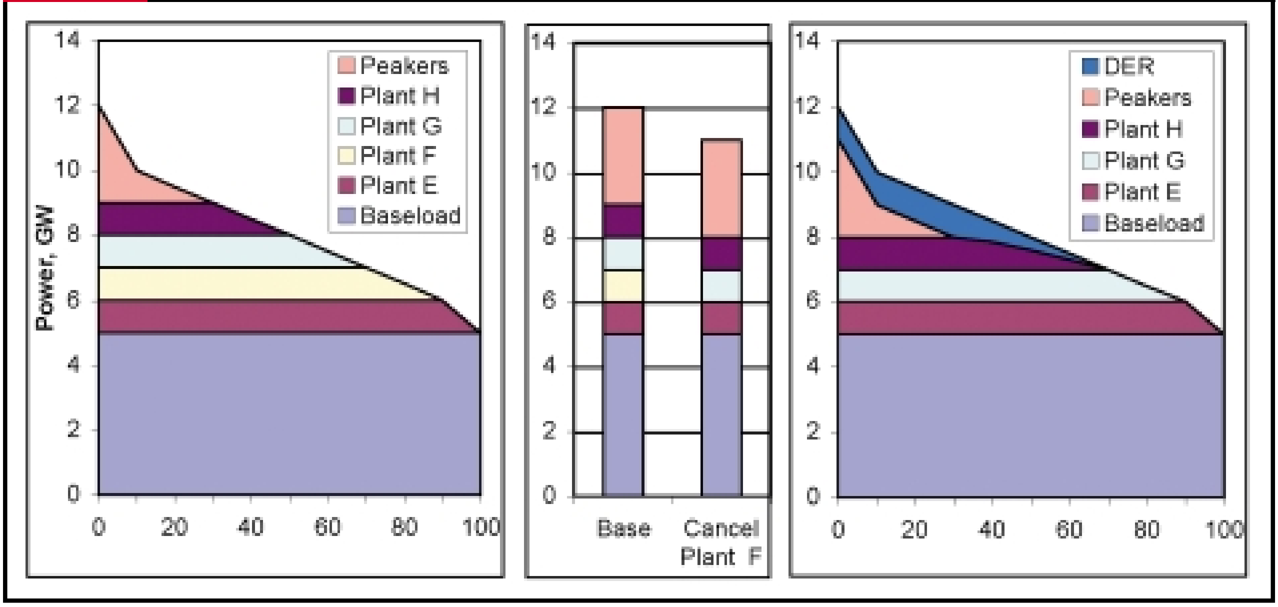


FIGURE 2 EXAMPLE OF CHANGE IN PRODUCTION FROM PLANT CANCELLATION PLUS DER



Dispatching to Meet the Load

Displacement depends on the generation resources that are "on the margin"—those that are turned off when an alternate source of production is supplied or demand is reduced. The fact that capacity is new does not mean it is on the margin. Utilities, or independent system operators in some locations, will use either variable operating costs or prices bid into a market from the plants in a region to establish an order of loading, or dispatch. That is, at any point in time, the last plant added to meet the load is the plant that costs the most to run, and is therefore the first plant to be turned off when the load is reduced. (Factors such as contractual terms, start-up costs, and transmission constraints complicate this simple description.) As demand increases, the more expensive plants are brought on line and prices rise accordingly.

In a process similar to stacking production in order of increasing cost, power demands over a given period can be sorted in order of increasing load. The resulting load duration curve (LDC) shows that portion of the period in which demand exceeds any given power level. Combining the LDC and the dispatch order, we can see the fraction of time that each plant is on the margin. Figure 1 shows the modeled dispatch of plants for MAAC in the summer of 2006. The plants along the top of the LDC curve are those on the margin, mainly coal, gas, and oil plants. Nuclear, some coal and the must-run capacity below nuclear are never on the margin.

DER as a Load Reduction

Operating DER will lower demand on the rest of the system. DER operating at baseload would take a slice off the top of the LDC equal to the amount of power produced by DER, and the plants along the top would reduce production in response. Weekday-only DER would lower demand mainly during the higher part of the LDC; plants operating on weekends and at night would not be affected. In the scenario where a power plant is canceled, first its capacity would be removed from the stack and all plants above it would increase their operation to compensate. Then the DER (baseload or peaking) would reduce the operation of the new set of plants along the curve. So operation of DER and cancellation of new plants can in certain situations increase the production from other plants (*see Figure 2*).

Results: Which Plants Were Displaced?

Our results were evaluated in two key steps: (1) calculating which central power plants reduced (or increased) production as a result of the addition of the DER; and (2) determining the consequent change in fuel use and emissions.

While the conventional wisdom is that adding DER automatically will displace new CC production, we found that assumption was not correct. In the scenarios with baseload DER, multiple types of production were displaced, even if gas CC capacity was canceled in response to the DER (*see Figure 3*). Coal capacity was displaced in all cases, representing those times when coal plants were on the margin. If no plants were canceled or if older plants were retired, then a fair amount of gas-fired combustion turbine production was displaced, even though oil-fired steam units were the main technology retired. Even if the DER experienced random forced outages, the other technologies would drop in the same proportions as shown in Figure 3 because the outages could occur randomly anywhere along the LDC.

The fuel prices in the reference cases were based on the fuel prices paid by the individual plants in the region between 1999 and 2001. The price averages are shown in Table 1. With the recent run-up in natural gas and oil prices, it was worthwhile to evaluate what would happen if higher prices were used [taken from a recent *Short-Term Energy Outlook* [1]]. With higher gas prices, the dispatch order changes so that gas-fired plants run less often. This in turn places oil-fired plants on the margin more often, so that they are displaced by DER more often (*see Figure 3*). Even in the cases where new CC capacity was canceled, the displaced production from CC represented less than 80 percent of the total displaced; without cancellation of CC capacity, the amount of CC capacity displaced was closer to 60 percent.

In the scenarios with DER operating during weekdays only, the impact of new gas CC capacity was more evident (*see Figure 4*). When 2,000 MW from new CC plants were canceled, their lost production was greater than the amount added from the peaking distributed generation. As a consequence, other central plants increased their production to make up the deficit. This somewhat overstates the amount of CC that would be canceled to compensate for the DER, however. Because the DER operated only during weekdays, weekend demands were unaffected and the overall peak demand declined by only 510 MW. If we canceled just 600 MW of new CC in order to maintain the same system-reserve margin, then no central generation increased its production to replace lost CC capacity; all declined. If old plants were retired (1,845 MW oil, 155 MW coal), then coal-fired electricity production declined significantly. And with higher gas and oil prices, oil generation was on the margin much more than in the reference cases, as in the baseload cases. Thus in the

TABLE 1 — AVERAGE FUEL PRICES USED

Fuel	Reference price, \$/MMBtu	EIA's *STEO* price, \$/MMBtu
Gas	3.99	5.41
Coal	1.30	1.31
Oil	3.73	4.42

cancel scenario, oil-fired steam units increased their production more to compensate for the loss of gas CC production.

Net Emissions Changes

As production from each generating technology changes, the energy use and emissions picture changes. The characteristics of the DER used for the analysis are based on a low-NO_x Solar Mars 90 combustion turbine and are shown in Table 2, along with pertinent parameters of the new CC plants and existing non-electrical boilers.[2,3] Both the DER and the CC facility are modeled as low-NO_x emitters, while the thermal boiler modeled has emissions based on the average value for gas-fired steam turbine boilers in the region. The Solar Mars 90 is a 9.5-MW turbine with dry low-NO_x combustion and selective catalytic reduction. With an electrical efficiency of 29 percent and a heat exchanger efficiency of 62 percent, the total efficiency of the DER is 73 percent.

Typically, NO_x emissions are reported in terms of lbs./MMBtu of thermal energy in. In Table 2, we also calculate the emissions in terms of lbs./mmBtu of useful energy out. For the new CC, the value is the amount of energy in divided by electrical efficiency; for the boiler, the value is the amount of energy in divided by thermal efficiency. However, DER technology in CHP mode creates both electrical and thermal output, and its relative emissions are the input amount divided by its combined efficiency of 73% [29% + 62% x (1-29%)].

FIGURE 3 — CENTRAL GENERATION DISPLACED BY 2,000 MW OF DER OPERATING YEAR-ROUND IN DIFFERENT SCENARIOS

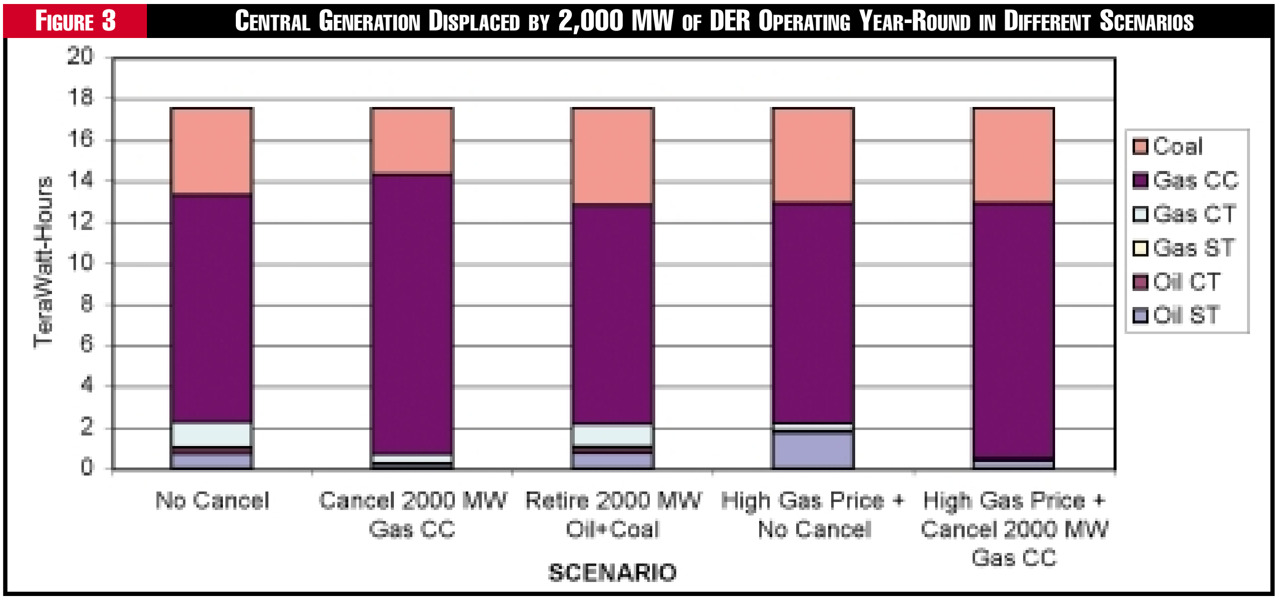


TABLE 2 — PARAMETERS FOR DISTRIBUTED GENERATION (WITH CHP) AND ALTERNATIVE TECHNOLOGIES

Model/Type	Electrical Efficiency	Heat Exchanger Efficiency	NO_x Emissions lb./MMBtu		CO_2 Emissions, lb./MMBtu	
			In	Out	In	Out
Solar Mars 90	29%	62%	0.022	0.030	117	160
New gas CC	49%	–	0.02	0.041	117	240
Non-electric boiler	–	72%	0.23	0.32	117	162

Source: Iannucci 2002; EIA 2003

Similarly, since all three technologies use natural gas, they have the same CO_2 emissions based on input energy. However, based on useful energy out, the DER with CHP is the least polluting. The CO_2 emissions of the Mars 90 also can be stated on an electrical output basis for comparison with the Regulatory Assistance Project (RAP) rule.[4] With a 29 percent electrical generation efficiency, 117 lbs/MMBtu into the system corresponds to about 1,400 lbs/MWh out of the system. The RAP model emissions rule for DER is 1,650 lbs/MWh in 2012.

When the added emissions from the DER (with CHP) are summed with the reductions from the CC and thermal system, the result is a net lowering of emissions in all cases. Figure 5 shows the net NO_x emissions for the peaking DER scenarios. In the scenario in which 2,000 MW of new CC is canceled, the central station emissions actually increase; therefore, if the DER provided only electricity generation, then emissions would be higher. However, the large savings from thermal system displacements results in a large overall emissions reduction. In all of the other scenarios, and in all of the scenarios for baseload DER, the reduction in electric system NO_x emissions alone is more than the increase from DER. Compound that with the savings from thermal systems, and DER is clearly a cleaner option.

Table 3 shows the net primary energy (fuel) and emissions changes from all of the scenarios studied. A positive value means that the overall amount of fuel used or emissions released is greater when the DER is included in the system than when it is not. A negative value means the system that includes DER uses less fuel or releases fewer emissions. As an example from the first line, if DER was used to generate 1,000 MWh, then the total net fuel use (if the DER provided only electricity) would increase by 3.1 TBtu. However, if thermal energy use is included, then the net total fuel used declines by 4.2 TBtu.

Moreover, in all cases, with DER providing only electricity, the fuel use and consequent CO_2 emissions from the DER were greater than from the displaced central generation, so there was a net increase. However, both the total emissions rate from the DER and the net system increase in emissions are less than the RAP model emissions rule for 2012.[4] Even better, when CHP was included in the model, the net fuel use and CO_2 releases were less than from the combined displaced electric generation and thermal energy production. Except for the scenario involving canceling 2,000 MW of CC with weekday-only DER operation, all scenarios had reductions in NO_x emissions even without the use of CHP. It could be argued that the most likely scenario is a combination of the bounding extreme cases considered here. That is, some plants will be retired, some new plants will be deferred, and other capacity plans will be unaffected. So although the scenarios are not equally likely, the average results of all the scenarios are informative. Without CHP, net fuel use and CO_2 emissions increased by roughly 250 lbs/MWh of DER generation, but net NO_x emissions declined. For every megawatt-hour generated by DER, total NO_x emissions from all sources declined by about 1 pound, which is significant when considered relative to the RAP model emissions rule limit of 0.15

TABLE 3 — NET CHANGES IN ENERGY AND EMISSIONS FOR ALL SCENARIOS STUDIED

(Positive Means a Net Increase and Negative Means a Net Savings.)

Scenario	Gas Price $/MMBtu	DER Mode	Net System Change (Per MWh Generated by DER): Primary Energy Used (MMBtu/MWh)		CO_2 (lb./MWh)		NO_x (lb./MWh)	
			Electric Only	With CHP	Electric Only	With CHP	Electric Only	With CHP
No cancellation	3.99	Peak	3.1	-4.2	160	-700	-1.0	-4.4
		Base	3.3	-4.0	120	-740	-1.3	-4.7
Cancel 600 MW new CC	3.99	Peak	3.7	-3.6	310	-540	-0.6	-3.9
Cancel 2000 MW new CC	3.99	Peak	5.7	-1.6	740	-110	0.6	-2.8
		Base	4.0	-3.3	290	-560	-0.8	-4.2
Retire 2000 MW old plants	3.99	Peak	2.8	-4.5	40	-810	-1.6	-4.9
		Base	3.2	-4.1	80	-770	-1.5	-4.9
No cancellation	5.41	Peak	3.4	-3.9	210	-640	-0.8	-4.2
		Base	3.3	-4.0	70	-790	-1.5	-4.9
Cancel 2000 MW new CC	5.41	Peak	5.2	-2.1	590	-260	-0.0	-3.4
		Base	3.8	-3.5	180	-680	-1.3	-4.6
Average of all scenarios			3.8	-3.5	250	-600	-0.9	-4.3

FIGURE 4 **CENTRAL GENERATION DISPLACED BY 2,000 MW OF DER OPERATING ONLY WEEKDAYS IN DIFFERENT SCENARIOS**

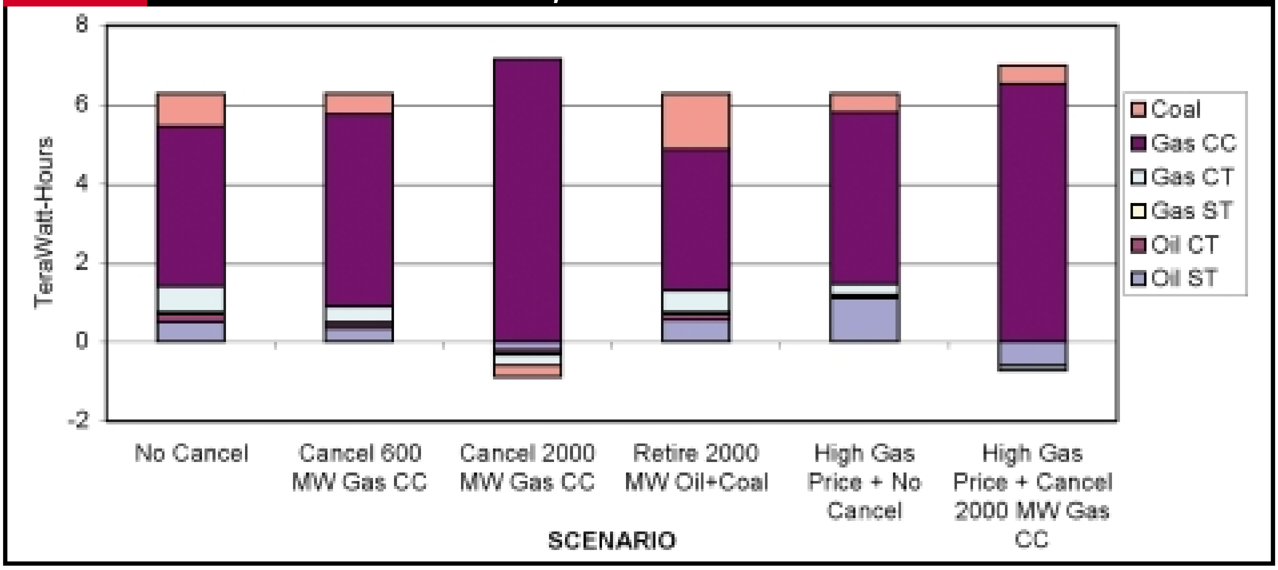
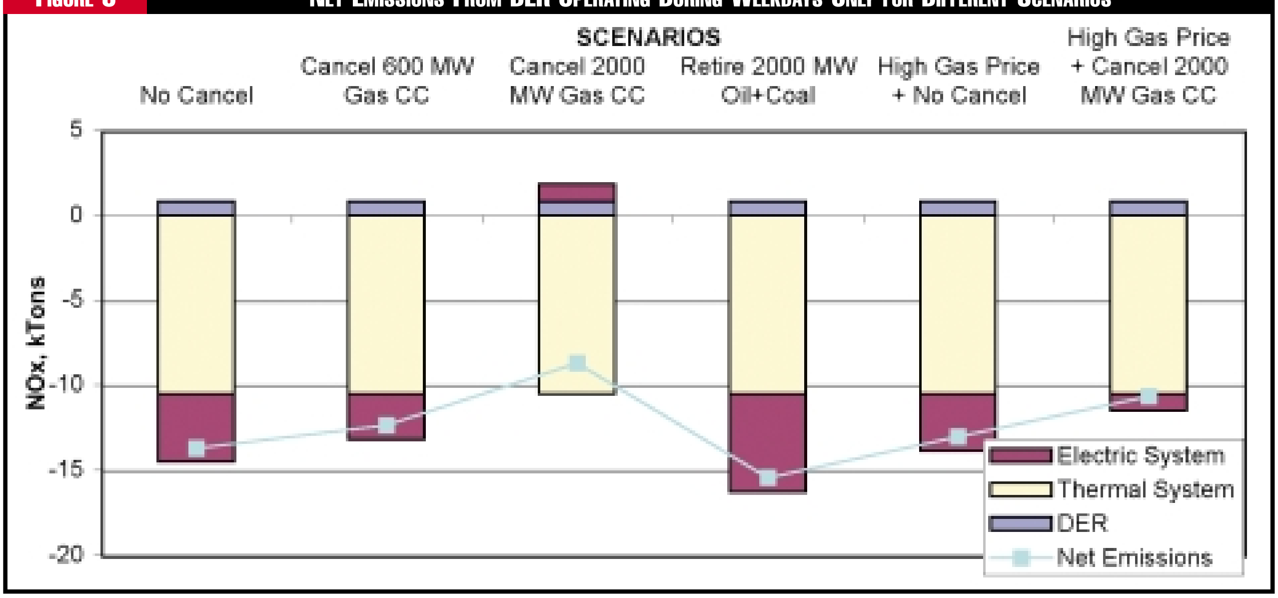


FIGURE 5 **NET EMISSIONS FROM DER OPERATING DURING WEEKDAYS ONLY FOR DIFFERENT SCENARIOS**



lbs/MWh in 2012. When CHP is included, the energy use, CO_2 emissions, and NO_x emissions all declined significantly, with net NO_x emissions declining by around 4 pounds for every megawatt-hour generated by DER.

Improvements in energy and emissions were significant across the broad range of scenarios. Even when new gas-fired CC capacity was canceled in proportion to the impact of DER on system loads, net NO_x emissions were reduced. Utilizing the exhaust heat from the DER compounded the savings and made DER with CHP a valuable component of the country's energy portfolio, reducing both total fuel use and emissions.

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Endnotes

1. EIA 2004, *Short-Term Energy Outlook*, U.S. Department of Energy, Washington, DC, June. <*http://www.eia.doe.gov/pub/forecasting/steo/oldsteos/apr04.pdf*>.
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3. EIA 2003, *The Assumptions to the Annual Energy Outlook 2003*, DOE/EIA-0554(2003), U.S. Department of Energy, Washington, D.C., January. <*http://www.eia.doe.gov/oiaf/aeo/assumption/index.html*>.
4. Issues Letter, July 2003, Regulatory Assistance Project, 177 Water Street, Gardiner ME, *www.raponline.org*.