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Emissions from Distributed Generation

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Abstract: This study takes a new approach to evaluating emissions from DG-CHP applications, by calculating emissions for the total energy supply system including both heat and power and comparing various DG-based and central station-based systems systematically across a range of HPR values. The overall approach is to first characterize typical DG technologies and applications in use as baseload DG today or likely to be used in the future. Then, a simulation model is developed and parameterized so that costs and emissions can be determined. The sensitivity of the results to greater levels of emission controls is also examined. Economic and policy implications are considered

Introduction

Electricity generation accounts for one quarter of nitrogen oxide (NO_X) emissions in the United States, over one-third of carbon dioxide (CO_2) emissions, and over two thirds of sulfur dioxide (SO_2) emissions.[1, 2] Numerous health and ecological problems result from these emissions, including elevated levels of tropospheric ozone and fine particles, global climate change, acidification, and eutrophication. Considerable effort has been made in designing emissions control strategies and technologies to reduce power sector emissions in order to mitigate these problems. For the most part, emission control efforts in the electricity sector have been aimed at large, central station generators, typically 25 megawatt (MW) or more, largely because thermodynamic and scale efficiencies make larger power stations the overwhelming source of emissions in this sector and their relatively small numbers make them easier for government to identify and regulate.

Recently however, technological and regulatory innovations have begun to enable small-scale, onsite electricity generators (typically gas-fired engines) to compete economically.[3, 4] In some European nations, distributed generation (DG) units have become a sizeable fraction of total electricity generation, typically designed to operate as baseload generation (that is, operated at rated load unless out of service for maintenance or other reasons).[5] One of the keys to the success of DG in Europe is the ability to use the waste heat from electricity generation, raising total system efficiencies to over 90% (higher heating value) in the best applications. The high efficiencies of such applications, commonly called Combined Heat and Power (CHP), offer both reduced costs and significant reductions of CO_2 emissions. Other factors may also drive increased deployment of DG in the future, including enhanced reliability and security, reduced need for transmission and distribution upgrades, and easier plant siting.[6, 7]

Air emissions from fossil-fueled DG units are a major unresolved issue, however. A wide variety of fuels, technologies, and operating patterns characterize small-scale DG applications, and only very limited in-situ measurements of DG emissions have been made. This has led to significant disagreements about the air quality impacts of DG and of appropriate policies to mitigate these impacts. On one hand DG emissions might impair air quality [8], while on the other, air quality policies may slow or stop the deployment of DG technologies.[9]

Analysis of emissions from DG conducted so far has focused on electricity-only applications of DG, with minor consideration given to the potential of heat recovery, while public policies are being developed on the same basis.[8, 10] For instance, recent legislation in California (SB1298) sets out a goal that DG emissions should meet the Best Available Control Technology (BACT) standard for central station power plants as soon as practicable, ignoring differences in the emissions from the onsite heat units that will be displaced.[11] A proposed regulation developed by the Regulatory Assistance Project (RAP) includes a CHP credit based on a single boiler standard, however there does not appear to be any quantitative analysis of the effects of this provision.[12, see section VI.B.] This approach is has the advantage of being relatively simple and easily related to regulation in the electric power sector but it treats the reduction in emissions from the on-site heat boiler in a cursory way. This is fraught with potential error as CHP applications combine formerly separate electricity and heat supply systems into one.

This paper provides estimates of costs and emissions for the total energy supply to facility (e.g. an office building or factory), meaning all technologies required to meet onsite demand for electric power as well as process and space heat. Estimates are developed for seven energy supply systems, two based on central station electricity generators and five based on small-scale fossil-fueled DG technologies. Onsite, gas-fired heat boilers are included as well, except for CHP applications where the recovered waste heat is sufficient to meet all process and space heating requirements. The policy implications are discussed.

Data and Methods

The overall approach taken here is to first characterize typical DG technologies and applications in use as baseload DG today or likely to be used in the future. Uncontrolled diesel engines, such as those from emergency backup generators are not evaluated because previous research has already shown their emissions are very high and regulations typically preclude their use as baseload generation.[8, 10] A simulation model is developed and parameterized so that costs and emissions can be determined.[13, 14] The sensitivity of the results to greater levels of emission controls is also examined.

This analysis differs from previous work in several ways. First, it looks at current practices in emissions control available today, not the relatively lax regulatory standards currently in place. Second, mass emissions for total energy supply (heat and power) under different DG applications are estimated, previous analysis has used emission rates or used air pollutant composite ratings, sometimes with a CHP 'credit' applied. The model used here permits us to quantify the costs and performance for multiple pollutants over a well-defined range of CHP applications and for a representative set of DG technologies to provide a clear understanding of costs and emissions for the entire energy supply system. Finally, the model includes transmission capital costs and energy losses, differentiated by customer class (residential, commercial and industrial).

Typical DG Technologies

Four DG technologies were identified as currently available (diesel internal combustion engines [ICEs], natural gas ICEs, micro-turbines, and gas turbines), while current interest in fuel cells in DG applications led us to add phosphoric acid fuel cells as well (with an associated reformer to turn natural gas into hydrogen). All of the DG technologies are assumed to have the air pollution control devices that are currently standard in Europe. Energy supply systems based on these five DG technologies are compared with systems based on central station coal steam turbines (CST) and combined cycle gas turbines (CCGT) In each case onsite, gas-fired heat boilers are included to meet heat demand, except for CHP systems that have adequate heating capacity.

Table 1 details the major cost parameters in the model. Data on DG costs and efficiencies were taken from published sources, and compared to case studies and manufactures data.[15-18] Capital and fuel cost data for centralized electricity plant and heat boilers were taken from US and UK government data, cross-checked with electricity technology survey articles.[19-24] Wellhead gas price is assumed to be $2.74/mCF, diesel fuel price 37.1¢/US gallon, and coal price $26.8/short ton. All fuel prices are 1999 averages, and are quoted in Table 1 as ¢/kWh (or $/MWh) .[25] Distribution costs are added to these values based on typical costs to different customer classes.

Table 1: Cost parameters

	Unit Size (MWe or MWth)	Capital cost ($/kW)	Fixed O&M cost ($/kW)	Variable O&M cost (¢/ kWh)	Fuel cost (¢/ kWh)
Gas ICE	0.2	750	15	1	0.89
Diesel ICE	0.2	700	15	1	1.02
Micro-turbine	0.06	800	15	0.6	0.89
Fuel cell	0.1	3000	15	0.6	0.89
Gas turbine	10	480	15	0.55	0.89
CCGT	100	550	15	0.55	0.89
CST	300	1100	15	0.4	0.42
Gas-fired heat boiler	0.2	200	10	0.25	0.89

The emission factors shown in Table 2 are based on all generation technologies being controlled using current practices for emission control in baseload DG applications in Europe, based on published sources and compared with manufacturer specifications, government publications and industry data.[15, 20, 26-31, 32 as well as manufacturer specifications] Factors for CO_2 and SO_2 emissions change with efficiency. For ICEs, current emission control practices are ignition timing delay and selective catalytic reduction (SCR); for micro-turbines, SCR; for gas turbines and CCGT, dry low NO_X burners and staged combustion; for CST, low NO_X burners and SCR; and for fuel cells with reformers, no emission controls are needed.

These values are similar to those found elsewhere in the literature for typical emissions, but are lower than those used in analyses based on U.S. regulatory standards.[8, 10, 33] They are higher, however, than CARB and RAP standards (with one trivial exception). They are also higher than the measured emissions for some of the best DG units currently in service in the United States. In its review of existing DG installations (gas turbines from ~1MW to 49MW and gas-fired engines from 65kW$_e$ to 3MW$_e$) the California Air Resources Board (CARB) found many units with performance at or below the 2003 California DG standards and RAP model rule standards.[11, 12] These applications typically use a combination of steam injection (for turbines) and catalytic controls, mostly SCR for turbines and 3-way catalysts for gas-fired engines.[11 Appendix B, Tables B-2 and B-4] Several of these turbines and engines met or were very close meeting to the much lower BACT requirements for permitted central power plants in California, which is the ultimate goal of SB1298. Thus the emission rate data used here for DG technologies reflects typical current technologies, not future regulatory standards or even current best practices.

The emission rates for commercial, gas-fired heat boilers used here are typical of those used elsewhere in the literature [34 Table 4, 35 Appendix A], and those recommended by the Natural Resources Defense Council for use when calculating CHP benefits.[36 pp. 33-34]

Table 2: Emissions factors (mean CO_2 and SO_2 values shown)

	Efficiency (% HHV)	CO_2 (g/ kWh)	SO_2 (g/ kWh)	NO_X (g/ kWh)	CO (g/ kWh)	PM_{10} (g/ kWh)	HC (g/ kWh)
Gas ICE	29	625	0.032	0.5	1.8	0.014	0.54
Diesel ICE	35	695	1.25	2.13	2.8	0.36	1.65
Micro-turbine	25	725	0.037	0.2	0.47	0.041	0.14
Fuel cell	38	477	0.024	0.015	0	0	0
Gas turbine	29	625	0.032	0.29	0.42	0.041	0.42
CCGT	50	363	0.019	0.195	0.07	0.041	0.05
CST	33	965	5.64	1.7	0.07	0.136	0.05
Gas-fired heat boiler	90	201	0.01	0.22	0.12	0.01	0.014

Transmission costs and losses are included for electricity, gas, and heat.[25, 29, 37] Gas-fired DG technologies and onsite heat boilers are assumed to require fuel distribution systems while CCGT are assumed to have direct access to the long-distance gas transmission system.[38] The cost of coal delivery is included in the prices used here and minimal losses are assumed. An electricity transmission and distribution system is assumed to be required by the centralized power stations. Heat losses have considerable site specific uncertainty, particularly with larger plants, typical values for commercial facilities are used here. Further details of this characterization of transmission costs and efficiencies are available.[5, 13]

Typical DG applications

Understanding the design and operation of DG is crucial to accurately estimating emissions. One of the key issues is that centralized power plants have greater scale and thermodynamic efficiencies compared to smaller DG units. Thus, in markets where DG is successful, units that recover waste heat for onsite use, called combined heat and power (DG-CHP), dominate because efficiencies of up to 90% (higher heating value) are possible. This negates the efficiency advantages of centralized power plants and reduces the total cost of energy supply onsite (both heat and power). For example, the Netherlands has over 5,000 gas ICE units of <1MWe each in DG-CHP applications, representing 1,500MWe, or 6% of national electric capacity.[5] Most of these installations are in greenhouses, industrial sites, indoor swimming pools, hotels, schools, and health centers.

Units in the very successful Dutch DG sector are sized are sized to provide all but the most extreme heat load requirements, and then are operated as baseload plants (meaning they run at rated capacity at all times except for maintenance), often selling significant amounts of power offsite. Heat is either used onsite or dumped to the atmosphere. Dutch baseload DG-CHP is typically found in clusters of small, identical units at one (or a small number of nearby) site(s) which are installed as a single package consisting of the prime mover, generator, heat exchangers and controls. They are remotely controlled from a central location, and typically have their emissions monitored at the same time.

The development of a successful DG sector results at least partly from the fact that Dutch electric utility companies have incentives to own and operate DG units and the most successful companies have developed flexible commercial arrangements with vendors and host sites.[5] Flexibility has allowed DG-CHP to flourish because the specifics of every potential host site vary widely in terms of energy demand patterns, technological sophistication, financial situation, and others. This approach further reduces the cost of DG-CHP, mainly by lowering operation and maintenance costs. In addition, the active participation by the distribution utility has allowed engineers to essentially eliminate concerns about safety as well as grid stability and control in systems with significant DG. To date in the United States, electric utility companies have not embraced DG, and in some cases regulators may preclude them from doing so. However, the underlying technological and economic factors that made baseload DG-CHP with active utility company participation a success in Europe are also present in the United States, so this analysis looks at the question of emissions from DG through this framework.

The Dutch paradigm of baseload DG-CHP has two main implications for emissions. First, these units already have communication links to the utility and they are typically monitored in close to real time for various operating parameters (e.g. coolant temperature) for preventative maintenance reasons. This issue will be treated in the Discussion section. Second, in this framework, electricity-only DG should be seen as a special (and unusual) case of DG-CHP, not the other way around as is typical in the United States. In order to analyze DG-CHP technologies and compare them with central station-based alternatives, it is useful to use the heat to power ratio (HPR) of each technology and each application, as given below.

$$HPR = \frac{energy\ produced\ (or\ consumed)\ as\ heat}{energy\ produced\ (or\ consumed)\ as\ electricity}$$

Table 3 contains average HPR values for aggregated energy demands for New York State and Florida, common definitions of combined heat and power.[11 Appendix C, 39], and typical DG-CHP technology outputs. Looking first at energy demand; in general more heat is needed than power overall, this being more true in colder locations and periods. Second, the range of these average demand HPRs is very similar to those for supply technologies. However, the actual HPR at any site will vary with time. Demand HPRs for the coldest days will be higher than those shown here (up to 8 on the coldest days in New York State), and that there is considerable variability in HPR over the course of a day and across different facilities. For instance, the monthly average HPR for Carnegie Mellon University (a large commercial load) has been calculated to vary from 0.3 in August to 2.2 in January, while hourly the HPR can vary over almost the same range over the course of a hot August day.[40] An important technical issue for DG-CHP systems, therefore is to match the HPR of the energy supply system with the HPR of the load. The closer the match, the more efficient the system will be.

Various implicit and explicit HPR definitions are shown in the center column. Electricity-only DG applications have an HPR of zero. The EPA's proposed regulations for industrial CHP set minimum heat and minimum power requirements to create an HPR range that includes the maximum HPR values for all DG-CHP technologies.[39] The HPR implied by the California Air Resource Board's CHP credit calculation varies from technology to technology because the definition is based on total system efficiency. Thus the minimum amount of recovered heat needed to attain that standard varies, and therefore so does the minimum HPR to meet the definition of CHP.

The HPR values shown in the right hand column are maximum values based on the inherent efficiency in electricity generation of each technology. Lower HPRs can be accommodated by dumping the heat to the environment, such as with a radiator (for engines) or by simply bypassing the exhaust of a turbine around the heat recovery unit. Note that technologies that are *more* efficient in converting fuel to electricity have *lower* HPR values.

Table 3: Heat to power ratio (HPR) values

NY and FL seasonal aggregated demands	HPR	CHP definition	HPR	DG-CHP technology outputs	HPR
NY: winter	3.0	Electricity only	0	Fuel cell	1.4
NY: shoulder	2.1	EPA	0.25 – 4.0	Diesel ICE	1.6
NY: summer	1.3	CA minimum for micro-turbine	2.0	Gas ICE	2.1
FL: winter	1.6	CA minimum for diesel	1.1	Gas turbine	2.0
FL: shoulder	1.5			Micro-turbine	2.6
FL: summer	0.82				

Note: Heat distribution losses are not included in this table

Modeling Framework

The energy system simulation model calculates supply costs (in ¢/ kWh) as the sum of capital, operating and fuel costs, including transmission system costs and losses. For simplicity, heat demand is converted to electric units with a simple unit conversion factor: 1kWh = 3412BTU. Capital and fixed O&M costs components are annualized and pro-rated at 10% over a 15 year period. An operational regime similar to those used in Dutch DG-CHP systems is used, the unit is operated at rated electrical capacity for 6,000 hours per annum is used. A total generation efficiency of 90% is used, with heat distribution losses factored in separately, implying a good match between the HPRs of the DG-CHP system and the load. Such applications are not uncommon among Dutch DG-CHP systems and may most readily found in industrial applications. Due to greater diurnal and seasonal fluctuation in energy demand, commercial and residential applications may not achieve such high overall efficiencies. The model also uses the emission factors in Table 2 and the various efficiencies of generation and transmission to calculate emissions on a mass-per-unit-output basis (g/ kWh).

Results

The cost and emission results are presented in Figures 1 through 7, which show the heat to power ratio (HPR) on the x-axis and the output measures (cost, in $/MkWh and emissions, in g/ kWh) on the y-axis. The denominator of these scales is *total* kWh supplied, both electric and thermal. Looking from left to right across these figures, therefore, means looking across a set of DG applications from electricity-only (e.g. a billboard) to applications in commercial buildings (e.g. a university) to industrial applications with significant process heat requirements (e.g. food processing). As the HPR grows, the importance of onsite heat boiler emissions grows, so that all energy supply systems begin to converge. Gas-fired combustion technologies are shown in orange, fuel cells in green, diesel engines in blue and CSTs in black.

Centrally-based energy supply systems have smooth curves as more and more is onsite heating is added as one moves to the right on the figure. At an HPR of zero, these energy supply systems will have only central station power plants in them, so the y-intercepts for the CCGT and CST curves will be the respective values in Tables 1 and 2. As the HPR goes up, onsite boilers are added to the energy supply system, so costs and emissions begin to converge to the value for the heat boilers. Since heat supply is less expensive and generally less polluting than electricity supply, these curves typically have negative slopes. If the electricity generation is less polluting (such as in the case of carbon monoxide, CO), the curves slope upward.

Energy supply systems based on DG-CHP have curves with two distinct segments, although this is not always easy to see given the scales of the figures. The y-intercepts for the curves for DG-CHP technology curves are also the respective values in Tables 1 and 2. After that, the first segment is from an HPR of zero until the maximum HPR for that technology is reached, and the second continues from that point onward. In the first segment, the numerator of the cost or emission value stays constant while the denominator increases, so these sections always slope downward (or are equal to zero). Up to this point, the energy supply system will have only DG-CHP units, beyond it, onsite heat boilers are added, so the curves then slope to converge with heat boiler emissions.

In all cases, the relative positions of the curves for the centrally-based and DG-CHP-based systems change significantly over the range HPR values examined. Some differences existed among customer classes in terms of energy distribution costs and efficiencies, but these were very small for emissions. For simplicity, only results for commercial customers are reported.

Costs

Heat is less expensive to supply than electricity, so the curves in Figure 1 all slope downward. For electricity-only applications, CCGT and coal ST are the lowest cost technologies, but combustion-based DG-CHP technologies begin to compete above an HPR of 0.5 and dominate past an HPR of 1. For HPRs ranging from 0.5 to slightly over 2, it is the larger GT-CHP systems that are lowest cost, however, these technologies may be too large for some applications. In this range, ICE-based DG-CHP systems are the least cost small-scale technology, above an HPR of 2.3, micro-turbine-based DG-CHP systems are least cost. Comparing these results to the aggregated energy demand for both New York and Florida, it appears that baseload DG-CHP using combustion technologies is competitive on a cost basis for much of the United States. Fuel cells are always most expensive, they have a cost premium of 25%-60% over the least cost technology and 5%-75% relative to central station-based systems. Finally, it is important to note that these results are for DG technologies at the scales given in Table 1 with only moderate numbers of installations. Larger or more numerous installations will drive down variable O&M costs and can greatly improve the economics of DG.[5]

Emissions

Figures 2-6 show the model results for the key pollutants, and Figure 6 includes a sensitivity analysis. Several general trends can be seen. First, CST and diesel-ICE based systems tend to have much higher emissions, with some exceptions (such as the low CST emissions of HC). Second, CCGT-based systems have low emissions at zero HPR, but at higher HPR values the efficiency of DG-CHP systems reduces or overcomes this effect, except for HC emissions. Third, fuel cell-based energy supply systems are generally the lowest emitting, with zero or near-zero pollution in electricity-only applications, including emissions from the reformer. However at HPR values over 1.4, onsite boilers are needed, which tend to raise system emissions so that, surprisingly, for PM-10 and NO_X, combustion-based DG-CHP systems have lower emissions than do fuel cell-based DG-CHP systems.

These results show that the net air quality effect of DG installations will vary significantly by pollutant and application. For instance, Table 4 shows the outcomes if a micro-turbine DG-CHP unit were used in an application that had HPR values that varied over the range given for New York (1.3-3.0) and installed operated as baseload generation meeting onsite heat demand at all times, and selling power to the grid or dumping heat to the atmosphere when either one is in excess of onsite requirements. In this HPR range, micro-turbines are among the lowest cost units, saving from 12% to 33% of total energy supply costs, depending on the baseline assumption (CST or CCGT). Emissions decrease for some pollutants (SO_2, NO_X, and PM_{10}) while they go up for others (CO and HC), however the increases are from very small baselines. Whether or not this is a beneficial trade-off will depend on local circumstances.

Table 4: Changes in New York if DG-CHP microturbines are operated as baseload

Parameter	Change
Costs	12%-33% reduction
CO_2	5%-45% reduction
SO_2	0%-98% reduction
NO_X	60%-90% reduction
CO	20%-100% *increase*
PM_{10}	50%-75% reduction
HC	200% *increase*

Note: Values derived from microturbine performance relative to CCGT and CST for HPR values of 1.3-3.0

The sensitivity analysis presented in Figure 7 examines different emission factors for NO_X emissions from CCGT and gas ICEs. The two curves labeled ‘current’ on this figure are identical with those in Figure 6. Emissions from energy supply systems based on higher- and lower-emitting CCGTs and a lower-emitting gas ICE are also shown. The ‘new’ CCGT has emissions typical of contemporary facilities, but not the lowest of new generators currently being installed. They are below the current CA NO_X standard for turbines in DG applications, but are about three times the CA BACT rates for central station generators. Similarly, the ‘new’ gas-ICE has emissions typical of contemporary facilities, but not the lowest of new generators currently being installed. This value is the current CA NO_X standard for turbines in DG applications, but is more than five times the CA BACT standard.

The key insights from this figure are the importance of boiler emissions and the advantage of efficiency gains through CHP. These combine to make the ‘new’ gas ICE-based CHP system cleaner than the CCGT-based system for HPR values of 0.25 and greater, and allow them to meet the CA BACT standard for HPR values of 1.1-1.6. In practice, CCGT emissions can be even lower than those shown here, with some plants permitted at 3ppm levels, however, this would not change the outcomes, except to move the intersection between the two lines to the right somewhat, raising the HPR value at which the gas ICE-based CHP system becomes cleaner than the CCGT system.

If the gas ICE emissions are reduced to about 0.33 lb/MWh (close to the RAP proposal), the DG-CHP system has lower emissions than current CCGT systems at an HPR of 0, and lower than the new CCGT when the HPR rises above 0.2. The efficiency gains of CHP drive emissions from this system very low, 35% below those from the new CCGT-based energy supply system, or better. Several engines in the CARB survey achieve emission factors in this range.

Net system efficiency varies significantly, as reflected in Figure 8. In electricity-only applications, CCGT-based systems have lowest CO_2 emissions, but above an HPR of 0.5 fuel cell-based systems are most efficient and have lowest CO_2 emissions. In addition, above an HPR of 1-1.5 the other DG-CHP systems have lower CO_2 emissions that CCGT. The CST-based system has much higher CO_2 emissions due to differences in fuels. Figure 9 shows the percent change in CO_2 emissions that would be achieved if each of the combustion-based technologies were replaced by fuel cells. At HPRs near or above 2, the CO_2 mitigation gained from switching from gas-fired, combustion-based DG-CHP to gas reformer/PAFC DG-CHP technologies is quite small, less than 10%. Heat recovery in CHP applications tends to reduce the efficiency advantages of fuel cells, as it does with central station generation.

This analysis shows that diesel ICEs, even those that use current emission control technologies have very significant emissions of NO_X, CO, SO_2, PM-10, and HC. This finding supports previous studies and like them, shows that the practice of using backup diesel generators for non-emergency use during peak electricity demand periods may cause significant air pollution problems. These results further suggest that diesel ICEs for baseload DG-CHP applications (or for grid support or reliability enhancement) will also be problematic, and possibly restricted only to areas in which air pollution is not an issue.

For most of the pollutants examined here (including CO_2, SO_2, NO_X, CO, and PM-10) energy supply systems based on gas-fired DG technologies have lower emissions than centrally-based systems only when in CHP applications. The data used here indicates that DG technologies have the greatest problem relative to centralized technologies in terms of HC emissions. For applications with HPR values of greater than 1 or so, technologies in use today can meet the most stringent emission requirements.

Fuel cell-based DG-CHP has the least pollution for applications with an HPR of less than about 1.5, and the least CO_2 emissions for HPR values above 0.5. This suggests that minimizing emissions from electricity production will require careful design and operational choices.

Perhaps the most surprising finding is that energy supply systems based on fuel cells do not always offer emission reductions over combustion-based systems. For pollutants, this is because as the HPR of the energy demand rises above about 1.5, emissions from the heat boilers that would be necessary to meet demand become increasingly important. For CO_2, this is because it is the recovery of waste heat makes the inherent efficiency of the prime mover less important. For such applications, technologies that are very efficient in converting fuel to electricity but also more expensive may not be economic choices.

Discussion

This study takes a new approach to evaluating emissions from DG-CHP applications, by calculating emissions for the total energy supply system including both heat and power and comparing various DG-based and central station-based systems systematically across a range of HPR values. Accurately characterizing baseline emissions (from both heat and power production) that will be offset by the use of DG-CHP is very important in this type of analysis. Here, relatively clean natural gas boilers were assumed. Had older boilers or different fuels (such as fuel oil) been considered, their higher emissions would increase the efficiency advantage of CHP applications.

A more difficult issue is choosing the appropriate baseline for the displaced central station emissions. Bluestein argues that "the average fossil unit emission rate is a good estimate for the displaced emissions" by showing graphically how different DG applications will affect the dispatch curve.[33] In his view, baseload DG-CHP would likely displace a wide range of generation types, from baseload CST to CCGT to peaking units. Others, however, take a view that the relevant comparison is with other new generators which would be needed if the DG-CHP were not installed, hence the BACT-based standard embodied in the RAP proposal and California's SB 1298.

There is some concern among manufacturers of engines and turbines that excessively stringent air quality regulations may preclude their products from the market, possibly in favor of fuel cell technologies. This may be particularly relevant for areas in which air pollution issues are less pressing than in California.

Some support for the concerns of engine and turbine manufacturers is provided by this analysis – there appear to be many potential DG-CHP applications where technologies with current emission rates can lower emissions from current levels, especially if they displace CSTs. The high costs of extremely clean DG technologies may limit their application and create lost opportunities for cost reduction and CO_2 emission reductions.

The current regulatory structure for air pollution from electricity generation leaves smaller installations essentially unregulated, except for product standards.[41, 42] However, DG developers typically need such exemptions because the air permitting process was designed with large central station generators in mind and are far too expensive for small DG applications. Thus, the standards in SB 1298 and in the RAP model rule are only required for DG applications that will be exempted from typical air pollution permitting processes.

However, these exceptions can add complexity. For instance, the RAP model rule has nine *sets* of separate emissions standards for four different pollutants, which vary by date of installation and type of application (emergency, peaking, and baseload). Such a complicated approach is challenging for both equipment manufacturers who prefer to design for a single standard, as well as DG-CHP developers who, as noted above, found that flexibility was important to success in the Dutch market. The problem with simpler regulations, of course, is that they are rather blunt instruments of public policy. If a single emission standard were to be adopted it would need to be protective in all cases, which means it would be overprotective in many.

One potential solution to this problem would be to allow DG applications to participate in market-based regulatory programs. Traditionally, it has been thought that the small size and large number of DG units made this impractical. However, the successful experience of baseload DG-CHP applications in the Netherlands (which includes central dispatch and remote monitoring) suggests that current sensor and IT technologies as well as commercial arrangements might make it feasible to include DG in cap-and-trade programs.[43-45] However, requiring DG-CHP units to attain the level of accuracy and reliability that the Continuous Emission Monitors used at central station plants would be economically infeasible for DG installations. Designing a cost-effective approach to this problem is an important research issue.

A cap-and-trade approach to controlling DG emissions would solve several problems. First, 'leakage' from the growing number of cap-and-trade systems would be eliminated so that regulators would not need to worry about growth in emissions from DG. Well-designed cap-and-trade programs work well, they lead to the expected emission reductions at relatively low costs.[43] Second, electricity-only DG applications that had particularly high value would be much easier to install even if they had relatively high emissions, they would simply need to purchase the requisite number of allowances. Third, equipment manufacturers would not have to certify DG units to a wide array of specifications, developers could simply factor in the cost of emission allowances when comparing different products. Fourth, since purchasing allowances would always represent a cost (and probably a rising cost) DG manufacturers would always have an incentive to improve performance and reduce emissions.

Future work

Although this paper makes a step towards more accurate estimates of air pollution emissions from DG, much still needs to be done. Monitoring of units in the field is needed to determine deterioration rates for emission control devices and part-load performance under field conditions. Many combustion technologies exhibit different levels of performance at partial and full loads.[46] Another important step would be to characterize the heat and power demands for different types of potential host sights, and to do so on an hourly basis or so to better understand how to match onsite energy supply with load. Since many parts of the United States have less consistent heating load, the use of absorption chillers as part of a combined-heat-cooling-power system may be needed to allow the recovery of waste heat. Other technologies such as heat pumps and thermal storage should also be evaluated as part of energy supply systems.

Even if emissions from DG are well understood, major questions about environmental impacts from DG will still need to be answered. Most importantly, the effects of DG emissions on air quality are unknown. Research to date has been focused on developing accurate emission estimates, ignoring so far differences in location or ambient conditions. Allison and Lents take a step in this direction, but even they do not quantify changes in air quality or health risks. In the absence of air quality modeling studies it is hard to know if the proposed standards are too stringent or not stringent enough.

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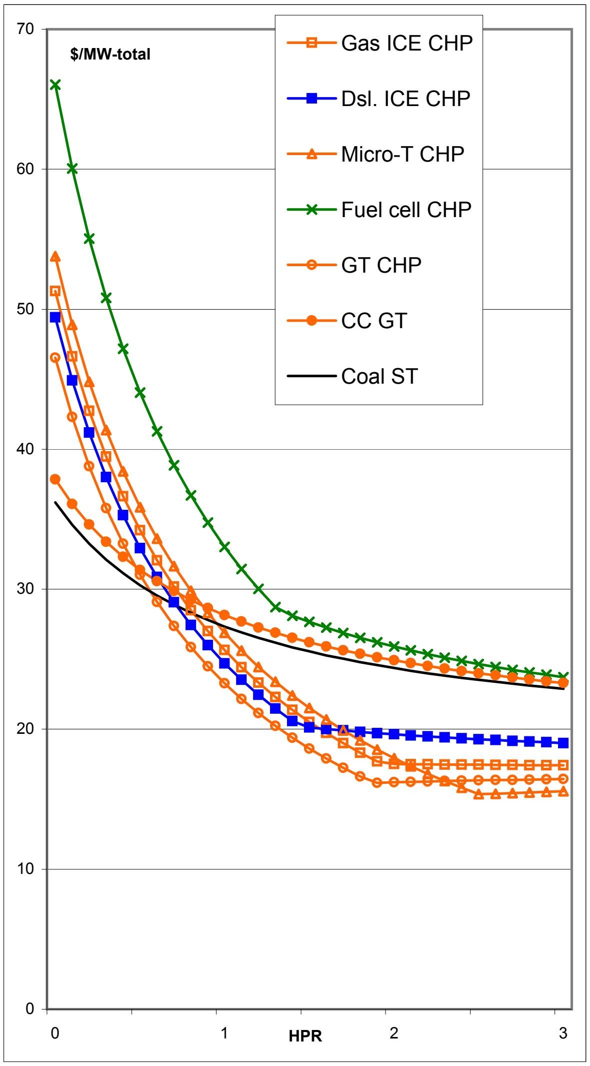

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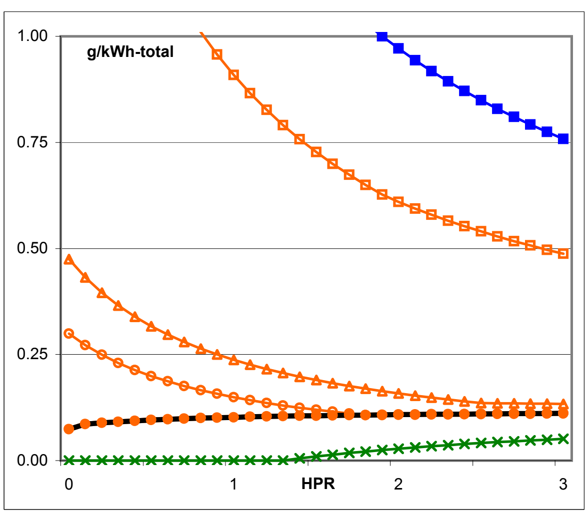

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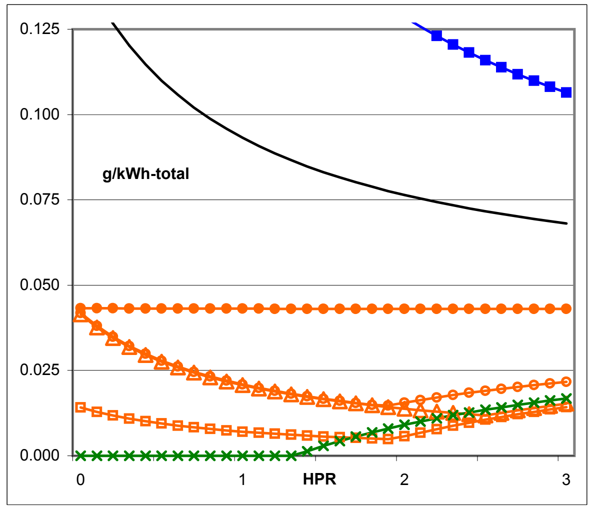
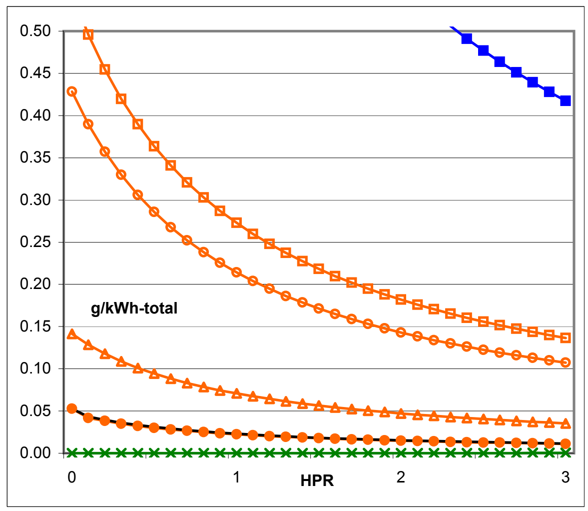


3 - PM-10 Emissions



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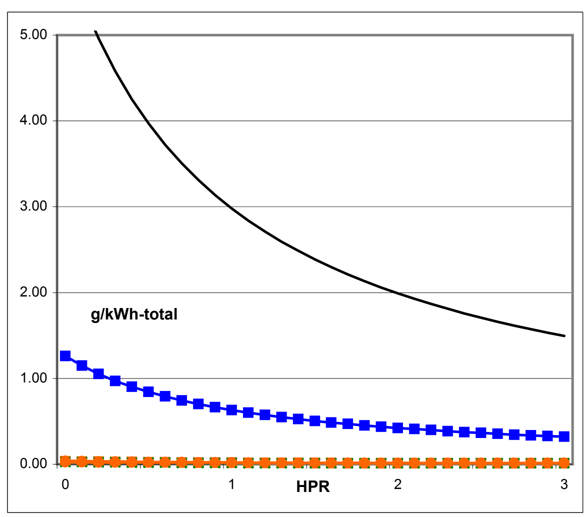

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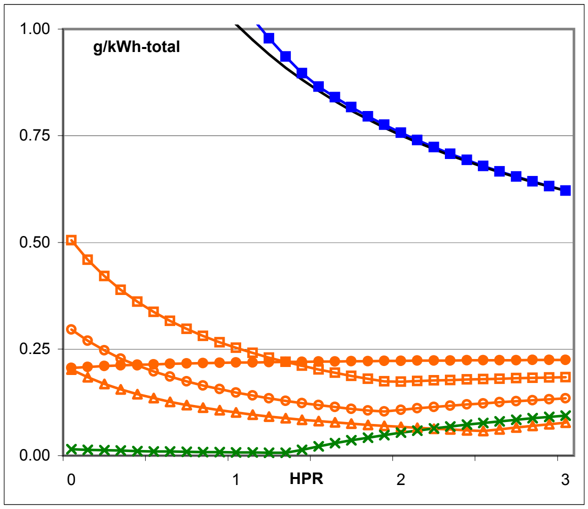
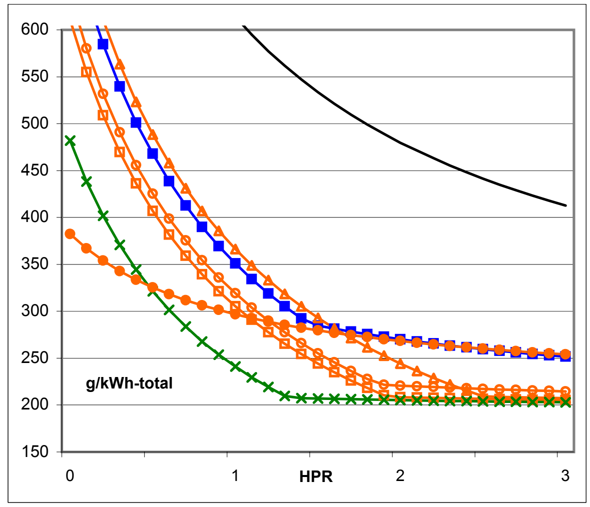


6 - NOx Emissions



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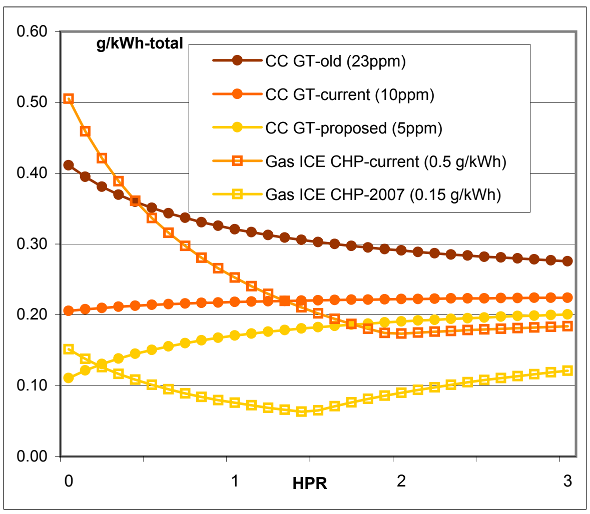
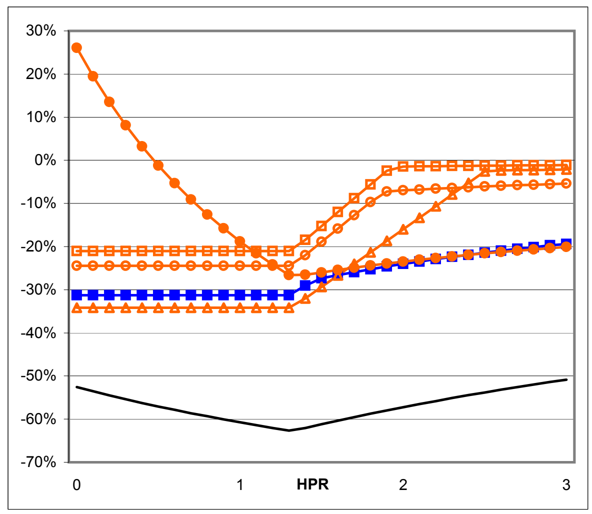


7 - NOx Sensitivity Analysis



9 - CO2 emission reduction if substituted with fuel cell