Survey of Emissions Models for Distributed Combined Heat and Power Systems

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ABSTRACT

Despite the multitude of benefits, relatively few tools exist for estimating the regional emissions implications of a combined heat and power (CHP) installation (the displaced emissions), or for predicting how CHP will affect constrained transmission systems or distributed emissions implications. Specifically, the impact of a CHP system on regional, utility-generated emissions needs to be quantified and better understood. In general, energy models seek to understand, model, and predict the behavior of energy markets and their effects on the economy. As proffered in ACEEE's Statement on Energy Information for the 21st Century, "There is a need for an improved characterization of both technology and behavior in the understanding of the role of energy in a changing world." That characterization and understanding, in essence, are the purposes of energy models.

The models surveyed in this study vary in design, scope, and detail, but they all seek to capture the functions of an energy economy and use knowledge of economic interactions to simulate the effects of economic and policy changes. In this document, Integrated Planning Model (IPM), Average Displaced Emissions Rate (ADER), Market Allocation (MARKAL), All Modular Industry Growth Assessment (AMIGA), Oak Ridge Competitive Electric Dispatch (ORCED), and National Energy Modeling System (NEMS) models are addressed. The U.S. Environmental Protection Agency's (EPA) CHP emissions calculator is also investigated. While the approximate operation of each model is discussed, this survey seeks specifically to explain how these models handle emissions and how CHP and thermal energy are considered within the models. Through a better understanding of the existing economic, energy market, and emissions models and their treatment of CHP, it is hoped that a simple, useful tool for the estimation of net avoided utility emissions can be designed.

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INTRODUCTION

Combined heat and power (CHP) is a proven technological solution to the challenge of efficient energy conversion. Because of its greater efficiency, CHP systems use less fuel to satisfy the energy demands for heat and power. Reduced fuel use naturally reduces combustion emissions. While this conclusion should be self-evident, quantifying emissions avoided by CHP systems remains a challenge. This report will look at this issue and review various models that have been developed to estimate the emissions impacts of CHP and other distributed generation technologies.

CHP (sometimes called "cogeneration") combines the production of power (either in the form of electricity or mechanical power) with the generation of employable heat. CHP installations usually exist as distinct, co-located heat and power equipment, although marketplace introductions have demonstrated the possibility of integrating heat and power functions in one unit. While electricity can be supplied remotely, albeit with some transmission losses, heat must be produced and consumed locally. Typical sources of heat demand[1] include steam for industrial process equipment, space heating, laundry, or appliance hot water. Certain systems can also use steam to provide cooling, thus providing a year-round thermal load. Examples of CHP systems encompass a range of industries and facility types, from large-scale industrial to small residential and agricultural. CHP offers combined power and thermal efficiencies on the order of 60–80%, whereas stand-alone installed combustion power or steam generation equipment averages around 30%. The efficiency gain from the displaced fuel effectively reduces greenhouse gas emissions by more than two times when compared to traditional separate heat and power equivalent technologies.

Combined heat and power provides economic benefits. In many installations, it is both cheaper and more reliable to produce heat and power together locally with CHP. Although time-tested and operational in a wide range of demanding installations, CHP remains at a low level of market penetration relative to the available opportunities. Various factors, including utility obstructionism, consumer ignorance and inertia, and adverse price signals have conspired to deny CHP the amount of utilization that its conferred benefits dictate (Brooks, Elswick, and Elliott 2006). Tools (e.g., Oak Ridge National Laboratory's Buildings Combined Heat and Power estimator) are available to estimate the economic feasibility of adopting CHP.

Aside from being economically advantageous and providing reliable power, one of the most obvious benefits of CHP is reduced combustion emissions. Tools exist for the calculation of local, immediate emissions benefits of CHP. Quantifying the net change in emissions at the site where the CHP is installed is fairly straightforward; the challenge has been in estimating the emissions avoided due to the utility electricity displaced by the CHP system. Essentially, this process is arithmetic—the emissions profile for the new CHP installation versus the previous boiler or other onsite equipment. The estimation of the net displaced emissions of a CHP system substituted for separate heat and power systems (the utility in the case of electricity) is more challenging. These avoided emissions offer benefits both to the CHP installer (from reductions

[1] Heat-consuming applications run the gamut from those demanding high quality heat (applications necessitating fluid, usually steam, at high temperature and pressure, such as a backpressure steam turbine or certain industrial processes) to low quality heat (such as domestic hot water or heat for an anaerobic digester).

in the firm's emissions) and to society as a whole (from the overall reduced emissions in a region). In fact, most of the benefits of a CHP installation are conferred to society.[2]

Despite the multitude of benefits, relatively few tools exist for estimating the regional emissions implications of a CHP installation (the displaced emissions), or for predicting how CHP affects constrained transmission systems or distributed emissions implications. Specifically, the impact of a CHP system on regional, utility-generated emissions needs to be quantified and better understood.

In general, energy models seek to understand, model, and predict the behavior of energy markets and their effects on the economy. As proffered in ACEEE's Statement on Energy Information for the 21st Century, "There is a need for an improved characterization of both technology and behavior in the understanding of the role of energy in a changing world." That characterization and understanding, in essence, are the purpose of energy models.

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MODEL INTRODUCTION

IPM and MARKAL both belong to the family of linear programming (LP) models. LP models solve for lowest cost configuration given a variety of technologies from which to choose and imposed constraints on the system (e.g., the need to minimize emissions or limits on technology availability). Whereas MARKAL is economy wide and can include economic feedbacks (through MARKAL-Macro), IPM is strictly an LP model that minimizes costs. However, IPM, in concert with ADER, contains more detailed information than MARKAL, allowing for more specific modeling questions. In contrast to the LP models, AMIGA and NEMS are economy-wide systems models that also handle energy. These models seek to simulate the resource allocation and market penetration of different energy technologies by modeling the economy as a whole—AMIGA approaches through specific policy questions, NEMS relies upon an exogenous macroeconomic forecast. Finally, ORCED is a spreadsheet model of similar structure to IPM, but of a much more modest scope. ORCED is designed exclusively for regional utility dispatch modeling. Table 1 summarizes the functionality of the different models.

[2] See, for description, the publications of the U.S. Combined Heat and Power Association (USCPA—http://uschpa.admgt.com).

Table 1: Energy Economy Model Functionality

Model	Least Cost Solver Method	Emissions	Thermal / CHP
MARKAL	linear programming	exogenous, user-assigned	no*
IPM	linear programming	exogenous, utility-reported	no
ADER	IPM parameter	NO_x, SO_x, CO_2, Hg—averaged rate	no
AMIGA	equilibrium solver	exogenous with limited new tech. options	small assigned demand and value
NEMS	equilibrium solver	exogenous with limited new tech. options	assigned demand, but not value
ORCED	historical sort	exogenous, utility-reported	no

* Such accounting is not intrinsic to the MARKAL engine, but a MARKAL submodel accounting for thermal energy has likely been created.

Both IPM and MARKAL are written in GAMS (General Algebraic Modeling System)—high-level modeling software for mathematical programming and optimization, tailored for complex, large-scale modeling applications. NEMS uses Fortran-based source code, AMIGA is written in the programming language C, and ORCED consists of Excel spreadsheets. With the exception of ADER, all models treat emissions as point source, generated according to actual indexed data of the power plants in the database. As discussed later, ADER calculates a generalized regional average emissions rate from the specific plant data.

AVAILABLE DATA

By its very definition, modeling seeks to imitate physical reality. The fidelity of any model is fundamentally influenced by the quality of the data on which it is constructed and run. Data that accurately captures the range of behavior of the target object is critical to a model's success and value. In the realm of emissions and energy, physical data is readily available in the form of reported and measured power generation and emissions values collected as part of the regulatory framework of the industry. Sensible selection of the subgroup of data that most accurately represents the behavior to be modeled is the most important characteristic distinguishing "good" from "bad" data.

There are several common sources for electricity-generating unit emissions data: National Electric Energy System (NEEDS), Emissions and Generation Resource Integrated Database (EGRID), Emissions Tracking System (ETS), National Emissions Inventory (NEI), and AP42, (accessed through FIRE), as well as historical data published by the Energy Information Agency (EIA). NEEDS is formatted for use with IPM specifically, while the other systems are of a more general nature.

NEEDS

The National Electrical Energy Data System is a database assembled by the EPA. NEEDS is based on the EPA's Continuous Tracking System (ETS/CEM) data, along with U.S. Department of Energy's (DOE) monthly and annual electric generation surveys, the National Electrical Reliability Council's (NERC) Electricity Supply and Demand database, and EPA's Information Collection Request database. NEEDS contains information on 12,144 electric generators, totaling over 757 GW of capacity. NEEDS is set up to satisfy the Generating Resource data for EPA's IPM model. Therefore, NEEDS is structured in IPM-readable format: namely, it organizes information into 26 electric power regions. IPM is used to evaluate the costs of satisfying emissions constraints on sulfur oxides (SO_x), nitrogen oxides (NO_x), carbon dioxide (CO_2), and mercury (Hg) from the electric power sector; therefore, that data is included in the information for each generator. Additional information includes a unique identification number, location, and capacity. As mentioned above, NEEDS and IPM are used by the EPA to prepare their base case studies, the last of which was completed in 2000. The EPA base case (projection of electricity sector activity that considers only federal and state air emission laws in effect or recently enacted and clearly delineated) is the starting point against which policy scenarios are compared—in effect, the future implications of current policy and legislation.

EGRID

The Emissions & Generation Resource Integrated Database contains information on almost all electric power generated in the United States (EPA 2006a). EGRID has 24 different data sources from the Federal Energy Regulatory Commission, EPA, and EIA, including EPA's Continuous Tracking System (ETS/CEM). ETS records plant-level data emissions that are monitored on site. Some estimates are also made according to technology type and application. The EGRID database organizes information by company, state, or power grid (NERC and power control subregions) region, and lists over 4,700 distinct power plants. For each generator, EGRID catalogues four primary emissions: NO_x, SO_x, CO_2, and Hg, reported in tons, pounds, input, and output rate. Plant-specific information, such as location, ownership, and a unique generator identification number, are also included. Finally, the plant capacity statistics are listed. EGRID was last updated in April 2003 (with 2002 data).

NEI

The National Emissions Inventory (NEI) is prepared by the Emission Inventory Group at the EPA. NEI relies on input from various industry, local, and state organizations, and contains information on both mobile and stationary emission sources. The inventory includes state emissions estimates for major facilities, and county-level estimates for smaller-scale emissions sources. The 2002 version of NEI (released on February 23, 2006) includes hazardous air pollutant (HAP) levels up to 1999. The precursors for the NEI, the National Emissions Trends (NET) database and the National Toxics Inventory (NTI), contain emissions inventories prior to 1999. The criteria air pollutants in the database are those regulated for health reasons by the EPA: CO, NO_x, SO_x, and particulate matter (PM10 and PM2.5). Volatile organic compounds and ammonia (NH3) are also included in the database (EPA 2006b).

Point sources, referring to stationary emissions sources identifiable by name and location and meeting a certain emissions level threshold of at least one criteria pollutant, are the sources relevant to the calculation of displaced emissions in the electricity sector. The sources for emissions contained in NEI include: EPA's emissions tracking system and continuous emissions monitoring system (ETS/CEM), DOE's fuel use data, state and local environmental agency data, and pre-existing emissions inventories.

EIA

The Energy Information Administration also includes a wealth of historical data (EIA 2005b). Unfortunately, the data proffered by EIA tends to be very aggregate, split amongst federal or state levels of specificity. EIA has historical data for states and regions (EIA 2006). This data, while helpful in validating overall, large-scale emission trends predicted by models, is not as helpful in providing data for input to a model seeking to simulate the effect of a single CHP installation. This information can be found at: http://www.eia.doe.gov/cneaf/electricity/st_profiles/e_profiles_sum.html.

ENERGY MODELS

MARKAL

MARKAL (Market Allocation) is a software model developed by the International Energy Agency, under its Energy Technology Systems Analysis Program (ETSAP) in the 1970s. MARKAL was designed to model the energy markets of a country—the conversion and consumption of energy. As an economy-wide linear programming model that has generic representations of power plants, MARKAL breaks demand into residential, industrial, commercial, and transportation sectors. The model can also handle resource supply. MARKAL is actually a family of models, and new databases are being designed and updated all the time by an active international user community. MARKAL consists of a core body of code, used with customized inputs and databases, rather than as a fixed entity. Therefore, in discussion of MARKAL, it is important to specify which user group (and implicitly which databases) and which family of models you are referring to. This survey deals specifically with EPA's MARKAL modeling efforts and is not intended to be a thorough analysis of all MARKAL capabilities. Aside from the EPA and a strong international user group, MARKAL is used by the Northeast States for Coordinated Air Use Management group (NESCAUM), as well as DOE's System for the Analysis of Global Markets (SAGE) model.

MARKAL Operation

Prior to running, the MARKAL model must be populated with data—resource information, as well as supply and energy demands. In this sense, MARKAL is like a blank spreadsheet calculator—a highly customizable tool that can generate very detailed or very general results depending on the specified data and constraints.

Constructed of a series of specified equations (typically several thousand), MARKAL optimizes a solution according to weighted factors and restrictions—considering such things as marginal energy cost ($/kWh) or emissions limits (ETSAP 1993). As a linear programming model designed to solve systems of equations, MARKAL associates emissions *coefficients* with every technology (according to the user input database of technologies). The model run then selects the combination of technologies that meets the specified emissions constraints while minimizing total energy system cost. The model considers six types of different demand periods: summer day, summer night, winter day, winter night, intermediate day, and intermediate night. This subdivision helps to model seasonal and daily demand fluctuations (Goldstein and Greening 2001). The model result from the selected combination is the output of the input data constraints and policies imposed.

With MARKAL, a series of model runs are made to examine a range of possible outcomes. Unlike some models, MARKAL requires energy demand and projected resource costs as inputs to the model. The first model run is used to establish a reference case in which the system of interest is unaltered. A series of runs is then made with successive changes in behavior (reductions in emissions of 10%, for example) by some future date before being stabilized. For each condition, MARKAL determines the least expensive combination of technologies to meet that requirement. Obviously, further restrictions increase the system cost. Therefore, the total future cost of emission reductions reflects the severity of the restrictions. By determining the marginal costs of emission reduction for each time period with MARKAL, future compliance costs can be plotted as continuous abatement cost curves (ETSAP 2006). MARKAL is also used to model grid transmission constraints. Multi-Area Power Simulation (MAPS), a proprietary MARKAL-based tool owned by General Electric, has successfully modeled electrical grid constraints for New York (Morris 2001).

MARKAL Unique Traits

One key limitation to standalone MARKAL modeling is that it does not respond to demand or price changes in resources. Because the model requires as inputs assumptions about energy sector demand growth for the model run, the model can only simulate variation to resource price or demand by coupling with MARKAL-MACRO. MACRO is a separate, simulated demand-response module that communicates with MARKAL. The MACRO coupling integrates the supply and demand sides of the model: MACRO generates an estimate for the impact on gross domestic product and allows demand to adjust accordingly. Other system modules exist to expand the functionality of MARKAL—for example, a price-demand elasticity module, and a module that allows MARKAL to solve for multiple goals (instead of just lowest cost).

Emissions in MARKAL

MARKAL does not allow a priori ranking of emissions abatement measures. The model chooses the preferred technologies and provides the ranking as a result. The EPA has developed a MARKAL database of emissions and technologies, including transportation, industrial, commercial, residential, and resource supply. The EPA MARKAL model places CHP in the industrial sector, and the model tracks process heat, but the model demand sector is fairly aggregate, lacking great detail.

IPM (Integrated Planning Model)

IPM is a detailed linear programming model, similar to MARKAL, but specifically designed as a planning dispatch tool for electric generation capacity in the United States. IPM was created by the EPA and ICF Consulting to model the national power market and is used privately by ICF to consult with select utilities on regional dispatch modeling. The discussion here concerns EPA's IPM efforts, not the proprietary system used by ICF. IPM requires a specified future fixed demand, unlike MARKAL; however, the model does not require resolution in the demand, but simply treats it as an overall objective to be satisfied. While ICF's electric utility model also includes sections to model gas and coal fuel supplies, IPM contains no built-in economy interaction. The EPA national IPM model, therefore, is mostly used for air quality or policy planning.

IPM Operation

IPM, in its EPA incarnation, relies on NEEDS, an extensive collection of data specifying the generation capabilities, emissions, and transmission characteristics of the domestic power grid. In turn, IPM is used to generate EPA's "base case," a simulated outlook of the domestic electric generation and emissions landscape, 5 to 10 years into the future. According to base case 2004,[3] EPA assumes a 2% energy loss for inter-regional transmission, consistent with the *Annual Energy Outlook* (EIA 2004). Base case 2004 also specifies the seasonal (summer/winter) inter-regional transmission capacities. While certain companies offer specific geographical grid congestion modeling, EPA simply specifies the grid constraints and an average transmission loss through its base case data file.

All existing U.S. grid-connected power plants are present in the model, and IPM aggregates electricity demand, transmission constraints and losses, and regional shortages to optimize the dispatch of specific generation, subject to restrictions and constraints. Whereas MARKAL is a general model for answering general questions, IPM is a detailed tool that supplies specific answers. For instance, IPM can be used to investigate the cost of emissions or supply constraints, and various other cases for defined regions. In addition to the grid-connected plant database, IPM has 15–20 types of generic generation units each with different performance characteristics and assumed emissions rates.

IPM approximates steam load in the industrial sector, thereby giving some added value to CHP capacity in specific markets, but does not otherwise account for thermal generation capacity or overall efficiency of CHP. IPM is further limited in that it does not account for energy efficiency measures implicitly, other than by explicit demand reduction scenarios run. That is, the model does not accord any added benefit to energy efficiency—only in a tight supply situation will efficiency gain favor.

IPM Unique Traits

Due to the nature of the model as a representation of the grid-connected power sector in the United States, IPM does not explicitly handle distributed generation or CHP. The model seeks to allocate large-scale generation to meet supply and emissions constraints, and largely ignores small distributed generation unless specified at input. The national IPM model seeks to determine national resource allocation over longer periods of time (e.g., 25 years hence). For

[3] EPA base case 2004 was the latest available through EPA at the time of writing. The transmission loss assumption, however, has remained constant since 2000.

example, if given sulfur dioxide allowable permit levels with emissions constraints, power systems, and reliability constraints for a 20-year timeline, IPM will solve for the least cost electricity generation to meet those targets, albeit without distributed generation as a supply tool.

Emissions in IPM

IPM treats power plants as point source emitters and contains indexed emissions data on individual U.S. grid-connected power plants. Future emissions are therefore based on their past emissions. IPM has a whole range of retrofit options for plants. To meet regional emission constraints, IPM power plants have options for repowering, retiring, retrofitting, or shutting down completely. Each option is associated with an additional cost. The model then optimizes the least-cost dispatch of power plants to meet emissions constraints. Where operational trading programs exist, they are modeled in addition to each specific operator. Although EPA and ICF share the common IPM platform, ICF uses a different set of (proprietary) assumptions for its work.

ADER (Average Displaced Emissions Rate)

ADER was created out of the IPM data to generate a generic regional emissions number with which to model national demand. The IPM model associates emission rates with each unit. For example, a gas turbine has a documented emissions level, with options (either refurbish, not dispatch, etc.) to meet these emission requirements. ADER was created to estimate a regional "picture" of emissions generated per additional kWh of electricity demand. ADER consists of a spreadsheet, generated from runs of the IPM model, with an average emission per kWh (the *ADER*).

The ADER methodology of calculating emissions is a parameterized, regional, time-indexed system. ADER is restricted to four different emissions species: SO_x, NO_x, CO_2, and Hg. The parameters are calculated to vary by year, season, region, and time of day (hour type) and are developed using the data from EPA's base case 2000 (Kerr and Morgan 2000). ADER parameters measure the total change in emissions (also known as displaced emissions) for each kWh change in electric demand/supply.

ADER uses individual regional electric load accounting to help predict displaced emissions from particular policy measures or technologies. In concert with IPM, ADER produces regional, national, short-term, and long-term estimates of displaced emissions (CO_2, NO_x, SO_x, and Hg) from electric generation. If the operational pattern and market penetration for a technology are determined, the parameters can be applied to derive a displaced emission estimate (Kerr and Morgan 2000).

ADER parameters are divided into distinct regional, seasonal, and time of day categories. Because ADER is derived from the EPA base case data, it shares the same assumptions and organizational structure, with some important differences. First, although IPM simulations consider the contiguous United States as 26 separate power market regions, ADER parameters are limited to five. The year is split into two seasons: summer (May–Sept. for high ozone levels) and winter (the remaining seven months). The hour types are split into three different day types:

weekday, weekend, and peak day. Rather than a full 24-hour day, ADER models 11 hour types, with divisions delineated at 5 and 7 am, noon, and 7 and 10 pm (segmented into the aforementioned day types). See Figure 1 for a graphical representation of the modeling system.

Figure 1: ADER Hour Type Structure

	Winter			Summer		
	Weekday	Peakday	Weekend	Weekday	Peakday	Weekend
12 AM - 1 AM	1	1	1	6	6	6
1 AM - 2 AM	1	1	1	6	6	6
2 AM - 3 AM	1	1	1	6	6	6
3 AM - 4 AM	1	1	1	6	6	6
4 AM - 5 AM	1	1	1	6	6	6
5 AM - 6 AM	4	4	1	9	9	6
6 AM - 7 AM	4	4	1	9	9	6
7 AM - 8 AM	2	2	5	7	7	10
8 AM - 9 AM	2	2	5	7	7	10
9 AM - 10 AM	2	2	5	7	7	10
10 AM - 11 AM	2	2	5	7	7	10
11 AM - 12 PM	2	2	5	7	7	10
12 PM - 1 PM	3	3	5	8	8	10
1 PM - 2 PM	3	3	5	8	8	10
2 PM - 3 PM	3	3	5	8	8	10
3 PM - 4 PM	3	3	5	8	8	10
4 PM - 5 PM	3	3	5	8	8	10
5 PM - 6 PM	3	3	5	8	8	10
6 PM - 7 PM	3	3	5	8	8	10
7 PM - 8 PM	4	4	5	9	9	10
8 PM - 9 PM	4	4	5	9	9	10
9 PM - 10 PM	4	4	5	9	9	10
10 PM - 11 PM	1	1	1	6	6	6
11 PM - 12 AM	1	1	1	6	6	6

Hour Block 11

Source: Kerr and Morgan (2000)

AMIGA (All Modular Industry Growth Assessment)

AMIGA is a national energy economy simulation "equilibrium" model used to explore economic effects of policy options related to emissions (carbon and otherwise) and energy efficiency measures. AMIGA holds a total of 200 distinct modules representing both production and consumption of energy, goods, and services, including: household and government demand modules; a transportation vehicle choice module; gas supply and electricity generation modules; a unit inventory of U.S. power plants; and five other modules in which various production activities and industrial processes are represented, including demand functions for energy (Hanson and Laitner 2004). These modules interact with each other in the AMIGA system, using variables in most cases represented by dollar indices, but for energy commodities represented by kWh or Btu. AMIGA includes all grid-connected utilities in the model, and models an additional 20 generic technologies.

AMIGA Operation

Whereas MARKAL and IPM use linear programming algorithms to solve systems of equations, AMIGA solves for least cost using a quick sort methodology after constraints (e.g., emissions compliance) are imposed. Unlike an LP model, AMIGA's equilibrium solver does not fix a demand throughout the model run—it establishes a baseline, then allows fluctuation. The total costs of production for each good or service are *sorted*, and the least cost options are selected until the demand is met—an equilibrium, where supply and demand balance for each good or service.

The equilibrium approach is faster and more robust than a linear programming approach, although you sacrifice some flexibility (modeling transmission losses, for example) by choosing this simplified solver. AMIGA is not capable of modeling local or regional emissions efforts due to its lack of geographical interactivity and the lack of resolution on a regional level.

AMIGA has a shell in C, and once set up, it runs and calls modules, and passes variables from one module to another as needed. AMIGA can be used to determine how price, income, and policy affect energy demand, and how changes in demand in turn affect supply (the "rebound effect"—analogous to a mechanical spring-damper system). For example, if increases in energy efficiency (hence a decrease in energy demand) raise income by 3%, the income boost then results in a slight increase in energy demand.

Demand sectors communicate in AMIGA. The model passes price data into a module that returns an external material and puts back the total quantity of intermediate demand. A demand reduction in natural gas, for instance, decreases usage but also reduces supply by driving down exploration in natural gas. For a given policy or year, investment is set once a demand profile is established, and the model is calibrated versus past data, then the model is allowed to run and equilibrate. Firms are assumed to maximize profit, and households are assumed to maximize utility.

AMIGA Unique Traits

AMIGA is not a forecasting model, but a simulation model. Another well-known model developed by Global Insight[4] and used by the EIA is used for forecasting—it ties a historical relationship, establishes a benchmark year, and allows the model to move forward in time. AMIGA establishes a baseline,[5] then allows policies to move the model to equilibrium. While EIA uses a full employment assumption, AMIGA assumes that resources can be allocated more efficiently (by buying a car that is more efficient, but may be more expensive, for instance). In the reference case, all resources are fully and efficiently allocated, then AMIGA moves the model forward and they equilibrate.

[4] Global Insight is a well-known economic consulting company. According to its Web site, (http://globalinsight.com), Global Insight helps "to untangle complex fuel-related supply, demand, and price relationships… We offer a broad range of analytical products and custom consulting services designed to highlight market risk, identify market opportunity, and support investment decisions."

[5] AMIGA's baseline relies on EIA's projection—which in turn relies on Global Insight's forecast model.

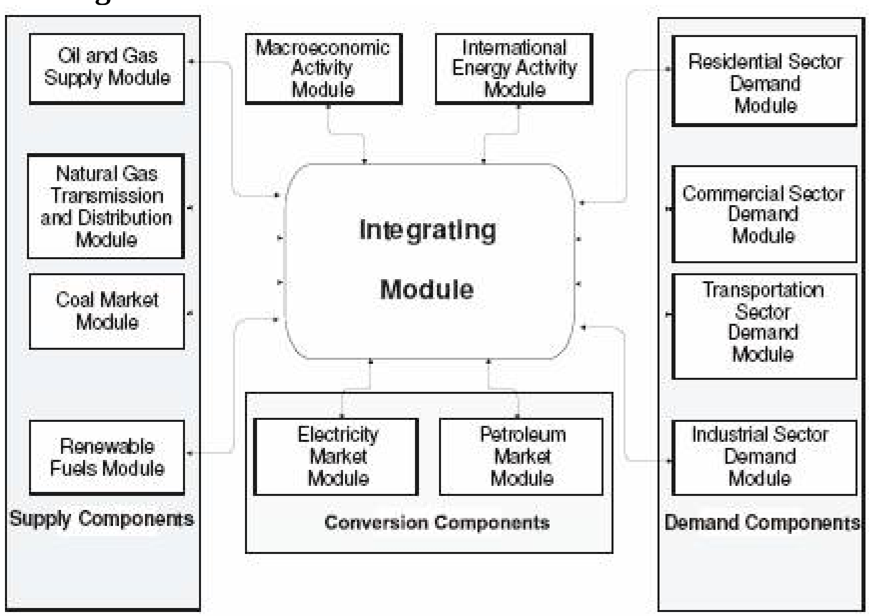
Emissions in AMIGA

AMIGA is an economy model that deals in energy, rather than an explicit energy (or electrical grid) model. Therefore, AMIGA does not model the electric grid or electric transmission. Instead, the AMIGA model deals with quantities of energy passed (without loss) among different economic sectors. Grid transmission, and the associated losses, is not a concern of the model. The AMIGA model allocates a certain percentage of natural gas that is dedicated for thermal use. The model also has a predicted level of CHP market penetration, and it accordingly dedicates percentage of natural gas to meet that steam demand with CHP. As with other technologies in the model, CHP is allowed to grow or contract according to imposed policies and price signals.

NEMS (National Energy Modeling System)

NEMS is a model developed by the Energy Information Agency, an independent agency within the U.S. Department of Energy responsible for energy data collection, analysis, and forecasting. NEMS is a modular economic modeling system, similar to AMIGA in structure. The domestic energy system is decomposed into fuel supply markets, conversion activities, and end-use consumption sectors. The NEMS modules attempt to represent all supply, conversion, and end-use demand sectors. Information exchanged among the economic sectors, or models, consists of delivered prices of energy and the quantities consumed by product, region, and sector. Detailed descriptions of energy production and use locations and energy products are included in NEMS. This detail is necessary because the economics of allocating energy products is strongly influenced by the product category at issue and regional differences in costs and other factors.

Figure 2: Basic NEMS Structure and Information Flow



Source: EIA (2005a)

NEMS Operation

The Industrial Demand Module in NEMS forecasts the consumption of energy for heat and power and for feed stocks and raw materials in each of 16 industry groups, subject to energy prices, value, and employment. In the industrial module of NEMS, the boiler, steam, and cogeneration (BSC) component consumes energy to meet the steam demands and to provide internally generated electricity to facilities. The boiler component consumes fuels and renewable energy to produce the steam and, in appropriate situations, generate electricity with CHP. The boiler component is estimated to consume 31% of total manufacturing heat and power energy consumption. NEMS uses the Global Insight Macro economy model.[6] NEMS passes variables back and forth to the Global Insight model to determine the impact on the economy.

CHP capacity, generation, fuel use, and thermal output are determined from exogenous data (i.e., from a database) and new additions are determined from an engineering and economic evaluation (i.e., from a payback calculation). CHP data is aggregated by Census region, industry, and fuel type for input to the model. EIA uses an internally developed database for NEMS. The data is available on a plant basis and identifies the capacity, generation, useful thermal energy, energy use by fuel, and the shares of that energy for electricity and thermal.

NEMS Unique Traits

To determine the penetration of CHP (called cogeneration by EIA), the investment payback period for each potential CHP system is calculated. The analysis considers the annual cash flow from the investment to be equal to the value of the *electricity* produced from CHP, less the cost of the incremental fuel required to generate it. (Note here that the thermal energy is not assigned a value.) The annual cost of fuel (natural gas) and the value of the electricity are based on the prices for the model year of concern, and the electricity is valued at the average regional industrial price (less standby charges—usually 10% of industrial generation rate). The price of firm-contract natural gas was assumed to apply. The payback is determined by dividing the investment by the average annual cash flow.

This payback calculation does not value heat generation and assures payback that is based only on electric generation. In addition, the calculation does not capture the common third-party leasing agreements that are often performed (which provide a positive cash flow to the facility from day 1). These reasons suggest that the rate of CHP adoption predicted by the NEMS model would be conservatively low.

ORCED (Oak Ridge Competitive Electric Dispatch)

ORCED is an annual dispatch spreadsheet model for analyzing the regional electricity supply using power plant information and hourly electric demand (ORNL 1999). ORCED uses plant dispatch information, fuel costs, and regional power demands to calculate air emissions, electricity costs and prices, and other operational factors of a regional electricity market. In the

[6] Global Insight maintains a proprietary modeling system for the U.S. economy, including a 5-year forecast (updated monthly), a 25-year forecast (updated quarterly), and an alternate scenario analysis.

1999 version of ORCED, power plant and demand data are provided for the ten NERC reliability regions from 1997 (ORNL 1999).

ORCED Operation

ORCED models the electrical system for a region by matching the supplies (defined by plant definitions of operations, costs, and emissions) and demands (defined by seasonal load duration curves) for a single year. Real-time prices, extra capacity, capacity payments, and other factors can present a complex financial picture for each plant and the system as a whole. Emissions from the various plants can be tracked, and limited optimization can be carried out. ORCED can roughly estimate demand response changes due to price variations, both overall and by the hour.

The ORCED model takes over 200 utilities and aggregates them to bins in several very complex Excel spreadsheets. ORCED is a purely electric model—the model does not treat thermal energy at all. Neither does ORCED have implicit generic components or assumptions for small-scale distributed generation—distributed generation is typically treated exclusively as a "negative demand" in any region.

The ORCED model, developed with support from the EPA and DOE, has two basic versions. The first version dispatches generation of the output available from 51 power plants to meet loads in a single region. Fifty of the units are characterized by capacity, outage rates, fuel type, heat rate, variable and fixed operations and maintenance (O&M) costs, and annual capital costs (based on construction cost, year of completion, capitalization structure, ongoing capital expenditures, and tax rates). The 51st unit is considered energy-limited (e.g., a hydroelectric unit). ORCED has also been expanded to dispatch 202 power plants. The second model version divides the plants between two regions. They are connected by a single transmission link that is characterized by its capacity, costs, and losses. The model uses separate load-duration curves to represent the time-varying electricity consumption in each region.

ORCED Unique Traits

ORCED is not as complex or detailed as models such as IPM or MARKAL, yet it seeks to capture the key features of the U.S. electricity system as it might function with competitive bulk-power markets. Generating units bid their variable costs (the sum of fuel costs plus variable O&M costs) into a market, the market selects the cheapest units to meet electricity demand for each point in time, and all generators are paid the same price during each time period (the price bid by the highest-cost unit then operating).

ORCED is very accessible, and modifications can be made relatively easily. For example, plant operations can be changed or tied to the operations of other plants, new emissions or emission policies can be added, or a subset of plants can be tracked separately from the entire group. These are just examples of what the flexibility of ORCED provides.

CHP EMISSIONS MODEL

While the surveyed models tend to select the entire economy or the domestic electric grid as the target of simulation, our aims here are more modest. We seek to focus exclusively on the implications from a CHP installation. The models surveyed either had little or no treatment for CHP and thermal energy. To model the emissions from any CHP installation, there are four emissions terms that need to be calculated:

1. produced by the proposed unit E_{prod}
2. displaced by the thermal production E_{therm}
3. displaced by the electrical production E_{elec}
4. displaced by eliminated grid congestion and transmission loss E_{grid}

The equation for net emissions from a CHP installation then becomes:

$$E_{net} = E_{prod} – E_{therm} – E_{elec} – E_{grid}$$

This equation should be applied for every emitted species of interest and is expected to be negative for all traditional power production sources.[7] The calculation of these terms will be dealt with individually below. The emissions can also be thought of in geographical terms: local and remote. Local emissions, captured by E_{prod} and E_{therm} (if a boiler is present), are determined by the equipment specifications of the proposed CHP unit and the boiler to be replaced (i.e., by the equipment itself). Existing tools[8] are currently available to facilitate this calculation. Calculating displaced emissions remotely (E_{elec} and E_{grid}), however, is much more nuanced and challenging.

Local Emissions

The determination of local emissions implications from a proposed CHP installation is well-documented and straightforward. This process should involve nothing more than a few simple calculations. If the technology has already been specified for the proposed installation, then emissions data can be gained from the equipment manufacturer. Unspecified technology can be approximated using industry averages for the equipment of interest (e.g., gas turbine or IC engine). Industry averages are available from several sources: The AP42 database is maintained by EPA and can be accessed with the Fast Information Retrieval Emissions (FIRE) program (EPA 2006c). There are close to over 9,900 technological categories in the AP42 database (91

[7] Certain hypothetical instances can be conjured, such as CHP displacing hydropower, where the installation might result in a net emissions increase.

[8] The "CHP Emissions Calculator" spreadsheet tool by the Energy and Environmental Analysis, Inc. (EEA) does a good job of calculating locally displaced emissions for a CHP installation. The spreadsheet calculates the annual emissions for a CHP system and the displaced electrical and thermal generation. It then calculates the net emissions. It does this by calculating the emissions rates (lb/MWh and lb/MMBtu depending on target) for CHP and the electrical and thermal generation of the following species: NOx, SOx, CO_2, and Hg. It multiplies these rates by operational hours (according to the load profile) to generated annual averages. One important point is that the EEA model assumes that CHP is primarily for electricity generation, with heat recovery secondary. There are no provisions for the counter situation. Also, the model makes no allotments for regional displacements.

coal-fired boilers alone!), including 140 specific to electrical generation. Example data taken from AP42 using FIRE is included in Table 2 below. The data are somewhat older, dating back to over 10 years in some cases, but are sufficiently disaggregated to allow approximation of installed equipment, and are notable for the included detail. Alternatively, various textbooks and other sources can provide coarser approximations of equipment emissions factors.

Table 2: Sample Data from the AP42 Database

	Emissions Rates (lb / MMBtu natural gas, per ton of coal)			
Technology	SO_x	NO_x	CO_2	PM
Natural gas electric turbine	Formula	0.32	110	0.0066 (.0047 condensable)
Coal-fired boiler	Formula	8.4	n/a	1.04

Locally displaced thermal emissions are theoretically simpler to determine than produced emissions, because the thermal generation unit (typically a boiler) is operational, relevant equipment specifications are on hand, and the emissions can be measured directly. If measurement equipment is lacking, an estimate of thermally attributed emissions is easily done. The sources used to estimate electrical production emissions also contain data on boilers.

Implicit in the estimation of locally produced CHP emissions is an understanding of equipment availability. Base-loaded equipment, expected to operate long duration, will have a different load profile than back-up or seasonal generation equipment. An accurate estimation of the operational period and load profile of the proposed equipment is essential to establishing viable emissions estimates.

Remote Emissions

The electrical emissions displacement calculation is not as straightforward as the local emissions calculation. The problem here is determining what type of generation will be displaced. The models surveyed use complex algorithms based on price, location, and emissions limits, integrated within a national framework, in order to determine how and when electrical generation is dispatched.

At issue here, in addition to the sorting difficulties faced for the displaced electrical generation emissions, is the sensitivity to location and time of use. Because this is a planning tool, there will not be time resolution (on the order of hours or days) necessary to adequately capture grid congestion. Therefore, an averaged value will be used. Given the difficulty in accurately predicting the electrical generation dispatch in many areas with multiple generators, it is likely that an averaged value for transmission loss will also be used. This averaged value will vary by region with the same resolution contained in the selected database.

The determination of remote emissions—the displaced emissions due to the proposed CHP generation—is much more difficult. The two primary issues for consideration in simulating the relationship between a new (or proposed) generation installation and its associated displaced emissions are geography and load.

Load considerations were briefly discussed in the context of production emissions, and the same issue is raised here. If displaced emissions are to be measured, the operational profile of the equipment (that is, the time of day, season, or conditions that dictate operation) must be well-established. This information is important not only to directly account for displaced electricity and associated emissions, but, perhaps more importantly, because of the variability of the dispatched and/or displaced generators. Electrical generation equipment varies according to time of day, season, and wholesale and contractual commodity prices, but primarily according to electrical demand. Therefore, the CHP operational profile will dictate what type of equipment (hence, what emissions) will be displaced. For example, if the CHP will be run only in emergencies, such as acute power shortages, then it is likely to displace combined-cycle gas turbines, which, although very clean, are typically expensive to operate. However, if the CHP is base-loaded, it will displace other base-loaded generation, such as coal and nuclear, as well as high-demand peaking equipment like the combined-cycle gas turbine. Of course, the exact makeup of displaced generation is highly dependant on region.

The second important issue in the determination of displaced emissions is geography. Although electrical distribution (from the grid to the customer meter) is universally regulated in the United States, electrical generation and grid transmission are in some degree of competition. Therefore, every customer in a given regional area uses the same provider to get electrical service from the grid to its site. This “last mile” service is regulated by the local public utility commission or equivalent, and prices are fixed. The entities who generate the power and distribute it, however, occupy an ever-changing landscape differing in price, ownership, and regulatory landscape according to the region. This complex structure makes it effectively impossible to establish any meaningful geographical correlation between electrical generation and consumption. Rather, a more simplistic and uninformed understanding of the electrical market is taken: all generators feed electrical power into the grid, and consumers take power from the grid. This reservoir model ignores the obvious physical impracticality of, say, a kWh generated in New York being consumed in California, but allows an (admittedly rough) treatment of an otherwise intractable problem of estimated displaced emissions due to electrical demand reduction (via a proposed CHP installation).

The estimation of displaced emissions is further constrained by the available data. Non-proprietary, publicly available data are often aggregated according to seemingly arbitrary geographical regions: the 10 NERC regions, states, or even counties. An unbiased approach will be used here: the displaced emissions will be reported for the region of interest from all of the surveyed data sources. For example, a planned CHP installation for Prince William County, Virginia, will return reported regional emissions averages for Prince William County, for Virginia, and for the NERC region. An assumed value will be used for transmission losses, as well.

EPA Emissions Calculator

A recently published tool by EPA has adopted much of the methodology outlined above, with the goal of quantifying the emissions benefits of a CHP installation. Originally adapted from a model put together by the Energy and Environmental Analysis, Inc., EPA’s CHP emissions calculator seeks to simplify the process of determining total NO_x, SO_x, and CO_2

emissions from an installed CHP plant. In addition to the arithmetic involved in calculating the local emissions change attributable to the CHP installation, the calculator seeks to determine the displaced emissions as well.

Calculator Operation

The Emissions Calculator is constructed of an Excel spreadsheet with macros and embedded database information. This construction allows the calculator to be self-contained, but also limits the amount of data that can be included. However, the spreadsheet is flexible enough to allow the usage of different emissions data if desired.

Calculator Emissions

The calculator uses five EGRID-based variations to approximate an electricity generation profile: a state average (year 2000) for all sources, and specific state averages for fossil fuel, oil, coal, and natural gas. The calculator also has seven individual generation technology-based profiles to choose from: a coal boiler with 1.5 or 3.8 lb/MWh NO_x, a coal boiler with selective catalytic reduction (SCR) and 0.8 lb/MWh NO_x, a gas boiler with 0.77 lb/MWh NO_x, a gas turbine peaker with 25 ppm NO_x, and a gas combine cycle turbine with 0.3 or 0.9 ppm $NO_{x.}$ It is also possible for the user to define three separate user profiles and to select one of those as the source of displaced electricity emissions. If a state average is selected as a generation profile, the displaced electricity source is specified by choosing either a state or the entire United States to average from. The transmission losses are set at 7% as a default.

Essentially, this approach relies entirely on either state-averaged data values from the EGRID database, or single-source emission profiles to determine the displaced emissions of a CHP project. This approach largely fails to realistically capture the displaced emissions from an installation. If a CHP installation displaces a single generator, the displaced emissions calculus is simple. If, however, the installation displaced central grid power, the determination of actual displaced emissions is essentially indeterminate, and the approximation of the displaced emissions is highly dependant on the level of resolution sought and the purpose of the calculation.

The nature of the electrical infrastructure in the United States and the interconnectivity between different regional transmission grids make the determination of a link between electrical production and consumption largely a statistical exercise. Hence, the state approach used by the Emissions Calculator may be adequate for some purposes. However, given that electrical infrastructure is generally divided by region rather than state, the state average approach has some inherent shortcomings. For instance, there are no coal-fired power plants in the District of Columbia, yet much of the power supply of the city is generated at coal plants located in the region. Examples abound of other states that are net energy importers. Of course, there are examples where a regionally constructed system would run into similar vagaries when trying to model instances near the regional border.

A flexible approach to calculating displaced emissions is paramount. Perhaps more important is an understanding of the area that acquires the CHP benefits. The EPA Emissions Calculator is useful for state-level calculations to which the displaced emissions benefits conferred to the state would be of interest. For a small community, however, such numbers would largely be meaningless.

CONCLUSIONS

Although a variety of well-established energy and emissions models exist, there are currently few tools available for the estimation of displace emissions in general, therefore the collective local and remote benefits of a combined heat and power system in particular. The absence of such a comprehensive tool penalizes a promising technology by not allowing appreciation of the extended benefits offered by CHP. The creation of such a tool might be approached by following the framework discussed here, initially providing coarse guidance and subsequently allowing the determination of specific benefits attributable to a CHP system. The CHP Emissions Calculator published by EPA is a good effort toward addressing some of these goals. However, the tool is too simplistic to allow geographical resolution of the displaced emissions. It is hoped that a more comprehensive tool, or the integration of the Emissions Calculator methodology into a more sophisticated model, will be performed.

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