# Framework for Identifying Distributed Resources Markets Consistent with NEMS/POEMS

## Subtask 1

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# Background

## Introduction

This report discusses the various aspects of the markets for distributed generation and identifies the unique characteristics of each of these markets particularly with respect to the modeling of these markets. The report characterizes distributed generation with respect to market segments and how they relate to specific technologies, spatial load issues, temporal load issues, grid connection issues, economic issues, and environmental issues. These are discussed to try to clarify how the distributed generation markets work and interact, and ultimately with the goal of modeling distributed generation in the context of the National Energy Modeling System (NEMS) and the Policy Office Electricity Modeling System (POEMS).

This first section of the report provides a discussion of the historical evolution of distributed generation markets and the reasons for the recent interest in distributed generation and provides some background for the NEMS and POEMS models. The second section provides a detailed discussion of the various markets for distributed generation, illustrating the markets as a cross-tabulation matrix of various actors versus various factors (incentives or motivations). The market "cells" in this matrix are discussed with respect to the various aspects of specific technologies, spatial load issues, temporal load issues, grid connection issues, economic issues, and environmental issues. The third section looks at a variety of current and forecasted demand model "categories" such as end-uses, building types, industry types, and time-of-day load shapes to help identify and characterize potential markets for distributed generation. The fourth section looks at how distributed generation is currently being modeled in the NEMS/POEMS demand models (residential, commercial, and industrial) and electricity model. The fifth section is a discussion of our proposed modeling for distributed generation within the context of the NEMS/POEMS models. The appendix of the report provides abstracts and summaries for a variety of selected papers dealing with distributed generation.

## Evolution of Distributed Generation Markets

Distributed generation has been defined in a wide variety of ways and can cover a great deal of activities. There are many aspects to it, but certainly much of the recent interest evolves from one aspect related to access to the grid. The recent activity and interest in distributed generation has been stimulated by rulings of the Federal Energy Regulatory Commission (FERC) in 1996 and various state legislation leading to retail choice. The effect is to enable users of distributed generation technologies to gain access to the electric power grid by requiring utility owners and power pools to offer non-discriminatory tariffs to third parties desiring to use the transmission system.

State level activities relating to the restructuring of the electric power industry have enabled retail wheeling that allows customers to purchase electric power more competitively from a variety of suppliers including from distributed generators. In response, the electric power system is evolving in many ways. Vertically integrated utilities are disaggregating into generation companies and into transmission entities such as POOLCOs. New organizations such as power marketers and energy service companies are forming to provide market organization and bargaining clout to consumers in order to provide more efficiency and value. Mergers and reorganizations have brought together a variety of organizations, such as electric and gas utilities.

The proposed Comprehensive Electricity Competition Act of 1999 (CECA) was recently introduced to further extend competition in electricity markets. The CECA contains several provisions designed to facilitate the adoption of distributed generation technologies. For example, CECA would require distribution utilities to allow distributed power facilities, including combined heat and power, to interconnect to their systems. It clarifies the tax life of distributed power facilities and provides for an 8 percent investment tax credit for highly efficient combined heat and power system for the years 2000 through 2002. CECA also requires net metering for small, on-site renewable generation systems. These provisions are expected to stimulate additional investments in distributed power and should be considered while additional modeling capabilities for distributed generation are developed.

Within its broader definition, distributed generation has been around for quite a few years. In this context it would include the generation of electricity by industrial and commercial entities. These would typically be either as cogeneration, which found its economies in using waste heat, or in generation using a variety of byproducts of industrial processes such as biomass in the paper industry. Under this broader definition it might also include much of the other recent non-central station generation such as generation by qualifying facilities under PURPA since 1978 and generation by independent power producers more recently.

However, it is a mistake to think that recent interest in distributed generation is related only to freer grid access and to electricity restructuring. It has also been fueled by the emergence of many newer, more efficient, less costly, more accessible modular technologies and the information systems that can control them. It is also fueled by the continuing and building interest in the use of renewables for power generation and the technological advances that have also made renewable technologies more efficient, less costly, and more accessible.

## Introduction to NEMS and POEMS

The National Energy Modeling System (NEMS)[1] is developed and maintained by the Energy Information Administration (EIA). NEMS is used by the EIA to develop the Annual Energy Outlook (AEO) projections and is also used by EIA to prepare analytical studies for the U.S. Congress and other offices within the Department of Energy. NEMS is a complex energy modeling system but is publicly available for other organizations to use. One example of an external organization working with NEMS is the extension of NEMS to create the Policy Office Electricity Modeling System (POEMS)[2] which substitutes a more detailed electricity model into NEMS. This electricity model, TradeElec, is related to the NEMS electricity model, but is designed specifically to analyze electricity restructuring issues with its much greater regional detail used for the modeling of electricity trading.

The projections in NEMS are developed with the use of a market-based approach to energy analysis. For

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[1] For a more complete description see *The National Energy Modeling System: An Overview 1998*, DOE/EIA-0581(98), February 1998, Washington, DC. (This is available at www.eia.doe.gov.)

[2] For a more complete description see Policy Office Electricity Modeling System (POEMS) Model Documentation, In Support of the Department of Energy's Comprehensive Electricity Competition Plan, ONLOC-99-05, May 1999, Dunn Loring, Virginia. (This is available at www.onlocationinc.com.)

each fuel and consuming sector, NEMS balances the energy supply and demand, accounting for the economic competition between the various energy fuels and sources. The time horizon of NEMS is the midterm period, approximately 20 years in the future.

NEMS is organized and implemented as a modular system. The modules represent each of the fuel supply markets, conversion sectors, and end-use consumption sectors of the energy system. NEMS also includes macroeconomic and international modules. NEMS is a regional system, functioning and reporting at the nine Census division level. The end use demand models and some other components operate at the nine Census division level, but the supply and conversion models operate internally using a variety of other, sector-specific regional definitions. The primary flows of information between these modules are the delivered prices of energy to the end user and the quantities consumed by product, region, and sector. The information flows also include other data such as economic activity, domestic production activity, and international petroleum supply availability. The execution of each of the component modules is controlled by the integrating module which also tests for convergence.

The POEMS model is a version of the NEMS which substitutes an alternative electricity model (described above), but otherwise includes all of the other component modules and retains the same integrating module and execution system. For various purposes or analyses, some changes are made to various algorithms in some component modules. This paper discusses distributed generation and makes proposals for the modeling of distributed generation. The modeling would be in the context of the NEMS and POEMS models and could be applied to one or the other or both.

# Discussion of Distributed Generation and Its Markets

The phrase "distributed generation" (DG) seems to be typically "contextually" defined. That is to say it typically takes on a different meaning depending upon the context of the report or study. It seems to be used in the literature and by interested parties in a wide variety of ways. For example, "Confusion exists regarding definitions and objectives of distributed utility and distributed generation ... including the size and applications of distributed generation ... ignorance/lack of knowledge ... is a major barrier to distributed generation."[3] Before we can intelligently attack the question of the growth in distributed generation and the possible methods for modeling and forecasting distributed generation, we must very clearly delineate what we are discussing and address all the aspects of it.

## Overall Category of Distributed Generation

There can be a fine line between what is and what is not to be included in the overall category of distributed generation. The following criteria are among the most common ways to make a distinction between distributed generation and other generation.

*Physical Location or Siting of the Unit*. One of the most common factors looked at is whether the unit is located at the central power station or whether it is located in a "distributed" setting, more particularly at or near the load. This is the definition that was used by the California Alliance for Distributed Energy Resources (CADER) when it stated that distributed generation includes measures that are "sited in or close to a load center or at a customer's site."[4] In general, most would agree that distributed generation refers more to units that are located in a "distributed" setting, at or near the load center, more towards the low-voltage end of the line.

*Capacity of the Unit*. Another common criteria for the dividing line for distributed generation is the capacity or size of the generating unit. A typical definition might be that DG includes "small (10 - 25,000 kW) renewable and non-renewable generation units and demand side management measures."[5] On the other hand the definition might also include "Distributed Generation denotes the stand-alone or system-integrated generation in small modular plants - ranging from a few kilowatts to over 100 megawatts (MW) - whether by utilities, utility customers, or third parties."[6] In general, most would agree that distributed generation refers more to smaller generating units, but smaller is hard to define.

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[3] *Distributed Generation Roundtable: Conference Proceedings*, California Energy Commission, April 1996, California.

[4] Minutes of CADER (California Alliance for Distributed Energy Resources) Kick-Off Meeting, October 15, 1996.

[5] *Characterization of Distributed Resource Technologies*, prepared by The Cadmus Group, SAIC, and OnLocation, July 1997.

[6] *Distributed Generation: Competitive Threat or Opportunity*, Preston, George T., and Daniel M. Rastler, *Public Utilities Fortnightly*, August, 1996.

*Ownership of the Unit*. A distinction is sometimes made with respect to the ownership of the unit; that is, whether it is owned by the traditional electric utility, by an end-use customer, or by a third party. In general, most would agree that this is more a legacy of defining the last 20 years of "distributed" generation in the form of PURPA and independent power producers, and in the current debate, ownership is not an integral part of defining what is and what is not distributed generation. An example of the general approach to ownership might be, "Distributed generation is defined as the integrated or stand-alone use of small modular resources by utilities, utility customers, and third parties in applications that benefit the electric system, specific customers or both."[7] Ownership is important, however, in defining the incentives and motives for distributed generation and much more will be said about this later.

*Purpose (Incentives and/or Motives)*. This is related to the location of the unit and to the ownership of the unit, but needs to be clarified on its own. The definition of the line for distributed generation is sometimes drawn at the point where the purpose or motive is to provide generation to bypass a transmission bottleneck.[8] This generation could be undertaken by the utility, by a third party, or by an end use customer (assuming certain incentives). Although this is considered to be one of the primary reasons for distributed generation, most commentators seem not to use it as the strict definition. In other words, there are many other incentives and motives for distributed generation. This might be the major cause (as discussed later), but is not necessarily the defining factor.

*Particular Type of Technology*. Some of the commentary on distributed generation keys in on the specific technologies and/or categories of technologies. For example, the discussion might key in on only renewable technologies, or might not include storage technologies or DSM options. This is a limiting definition and is not typically applied to more general studies.

*Mode of Operation*. A distinction is sometimes made with respect to whether the distributed generation is relatively unencumbered by the rules of operation of central power systems such as scheduling, pool pricing, dispatch, etc. Most would agree that distributed generation would be defined as generation that is relatively independently operated.

Using some of the various "line-drawing" factors above, we might be able to better define what we mean by distributed generation. This might best be described as:

> "Despite the diversity in nomenclature, there seems to be general agreement that the central issues in defining DG relate to the purpose, the mode of operation and the location of the generation plant. In terms of purpose, DG is perceived to be a flexible source of power compared to centrally generated and bulk-transmitted electricity. In terms of mode of operation, DG is viewed as a source that is relatively unencumbered by the rules of operation of central systems (scheduling, pool pricing, dispatch, etc.). Finally, in terms of location, DG is generally located at the low-voltage end of the local distribution system, often at or near the load center. The issues of the size of the unit and of ownership are, in our

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[7] *What is Distributed Generation?*, Electric Power Research Institute, 1997, Palo Alto, California.

[8] A transmission bottleneck can be caused by a variety of sources including time-of-day loads, load growth due to economic growth, congestion, old or faulty T&D infrastructure, etc. The idea is that it might be possible to build distributed generation at a lower cost than to improve or extend the T&D network.

> opinion, not critical to the definition of what constitutes DG."[9]

The same authors go on to define distributed generation as:

> "...generation meant primarily as an alternative to electricity generation using large, traditional power stations and the accompanying bulk transmission and distribution systems; it may be located in either urban or isolated settings, generally at the low voltage end of the distribution system, and close to load centers. The plant can be owned and/or operated by private or public utilities, utility customers, or third parties."

This is a fairly general definition and is one that will suit our purposes well. It is very encompassing and will include a wide variety of generation functions. Unfortunately, it does not draw a dramatic, distinguishing line between distributed generation and other generation, nor definitively answer all questions, but given all the factors above, that would be difficult to do. However, this definition does set the stage for a fairly clear understanding of what distributed generation is and makes a fairly clear line for most of it.

## Comparative Costs of Distributed and Central Station Generation

It is instructive to review some of the costs that are associated with central station electricity generation and compare them to the costs for some distributed generation technologies. The costs, the table, and much of the discussion for this section come from an article by Pfeifenberger, et. al.[10]

During the last two decades, steam turbine efficiency has improved, but it has been significantly outpaced by smaller gas turbines (GTs) in combination with heat recovery steam generator systems (CCGTs). The investment cost of new central-station CCGTs has decreased to $300-$600 per kW installed capacity and natural gas has become available to electric utilities and independent power producers at $2.00 to $2.50 per million Btu. With a conversion efficiency of 50 percent and above, base-load operation of CCGTs allows for total production costs (including non-fuel O&M costs) under 3 cents per kWh. At a typical 60 percent capacity factor the total costs of a new CCGT are closer to 3.5 cents per kWh. (Note that this is often still below the average cost of existing steam generators and turbines, even though they may have been well depreciated.) Distributed generation resources compete with the power from central stations that is delivered to end users through the transmission and distribution system. Adding transmission costs (including losses and ancillary services), the long-run incremental cost of power at substations (and for large industrial users) is approximately 3.5 and 4.0 cents per kWh for base load and a load factor of 60 percent respectively. Average distribution costs (including customer service) typically add another 2 to 3 cents per kWh for residential, commercial, and small industrial customers, increasing the average long-run incremental cost of serving these customers to around 5 to 7 cents per kWh. These costs are shown in Table 1.

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[9] *Distributed Electricity Generation in Competitive Energy Markets: A Case Study in Australia*, Sharma, Deepak and Robert Bartels, in *The Energy Journal, A Special Issue*, 1997.

[10] *What's in the Cards for Distributed Resources?*, Pfeifenberger, Johannes P., Philip Q Hanser, and Paul R. Ammann, in *A Special Issue of The Energy Journal, Distributed Resources: Toward a New Paradigm of the Electricity Business*, 1997.

**Table 1. Cost and Efficiency Estimates of New Generation Technologies**
(from Pfeifenberger, et. al.)

| Type | Fuel Efficiency (Percent) | Fuel Costs ($/MMBtu) | Investment Costs ($/kW) | Target Utilization (Percent) | O&M Costs (¢/kWh) | Total Cost of Power (¢/kWh) |
|---|---|---|---|---|---|---|
| **Central Power Stations:** | | | | | | |
| Comb. Cycle GT | 50 - 58 | 2.0 - 2.5 | 300 - 600 | > 80 | 0.2 - 0.5 | 2.5 - 3.5 |
| Gas Turbine | 32 - 38 | 2.0 - 3.0 | 180 - 350 | < 20 | 1.0 - 2.0+ | 8.0 - 15.0+ |
| Coal Plant | 34 - 40 | 0.8 - 1.4 | 800 - 1400 | > 80 | 0.4 - 0.8 | 3.0 - 5.0 |
| **Distributed Generation:** | | | | | | |
| Base-Load GenSets | 30 - 40 | 2.5 - 6.0 | 700 - 1800 | > 80 | 0.6 - 2.0 | 4.5 - 12.0 |
| Stand-By GenSets | 20 - 30 | 2.5 - 6.0 | 250 - 500 | < 10 | 4.0 - 7.0+ | 15.0 - 25.0+ |
| Micro-Turbine Generators | 20 - 30 | 2.5 - 6.0 | 500 - 700 | > 50<br>< 10 | 0.2 - 0.5<br>1.0 - 2.0 | 5.0 - 12.0+<br>17.0 - 30.0+ |
| Fuel Cells | 40 - 55 | 2.5 - 6.0 | 2000 - 3000 | > 80 | 0.4 - 1.0 | 8.0 - 12.0 |
| Solar Systems | -- | -- | 3500 - 5500 | 20 - 40 | 0.1 - 0.5 | 15.0 - 60.0 |
| Wind Generators | -- | -- | 800 - 1800 | 25 - 50 | 0.6 - 1.5 | 5.0 - 15.0 |

The authors state that:

> "At these costs, central station generation creates a significant hurdle for distributed generation technologies to overcome in the base-load and intermediate-load market segments. In fact, few distributed generation technologies currently come particularly close to being cost competitive on average. New micro-turbine generators (currently available in the 50kW to 100kW range) appear to be most promising in that respect. At investment costs of currently $500 to $700 per kW, average production costs can be as low as 5 cents per kW -- even without use of waste heat. However, even as the capital costs of such micro-turbine gensets fall to a projected level of $300 to $400 per kW over the next several years, such gensets may provide a truly competitive alternative to delivered central station base- and intermediate-load power only if the local utility's transmission and distribution (T&D) charges (including charges for stand-by service and stranded cost recovery) can be avoided."
>
> "Investment costs for many other base-load and intermediate-load distributed resource technologies remain well above $1,000 per kW and fuel available to end users tends to be considerably more expensive than fuel available to central power stations. ... As a result, in the production of electric energy (i.e., base-load power), distributed resources will struggle to be competitive with central station generation. Although the capital costs of distributed resources continues to decrease, the competitive disadvantage in the production of energy is unlikely to disappear any time soon. In part, this is because the production costs of power from central power stations has been continuing to decline as well."

> "Other potential advantages of central power stations include: (1) scale economies in plant development (e.g., siting, permits, fuel contract negotiations); (2) scale economies in control, operations, maintenance; (3) rapid decrease in the cost of pollution controls (e.g., low-emission gas turbines with 10-15 ppm $NO_x$ and falling); (4) load diversification (i.e., pooling of many customers reduces coincidental peak load); (5) inexpensive repowering of existing plants; and (6) modular designs that both enhance central power stations' operating flexibility and permit their capacity to grow with the level and type of utility load (e.g., peak-load gas turbines can "grow" into higher capacity, higher efficiency, base-load CCGT units)."

The key phrases in the previous paragraphs are "competitive on average" and "in the base-load and intermediate-load market segments." Any utility could use any distributed generation technology at the central power station if it were truly to their advantage. The overriding determining factor is in the costs of transmission and distribution and in the various congestion and constraints associated with it. Despite the fact that distributed generation does not appear to be competitive on average and in the base-load and intermediate-load markets, there still are markets for distributed generation. The authors state that "despite the advantages of central station generation, there should be little doubt that distributed resources will be able to penetrate *some* market segments." They provide their four primary reasons why distributed resources might be attractive in some markets. These are discussed below.

First, the distributed generation of electric power can be cost effective in markets where thermal energy is available and valuable. (We might also include the availability of other energy sources in the form of byproduct fuels. This is especially true, for example, of biomass in the paper industry.) The thermal energy is valuable for distributed generation (cogeneration) when the generation is close to the source of thermal energy and especially when the thermal energy is available year-round.

Second, distributed generation markets can be created by inefficient pricing. Some customers can benefit from distributed generation even though their costs exceed the incremental cost of power delivered from a central power plant. This is because the customer's electricity rates are set by the utility to recover the average costs of all utility resources (including high-cost plants and power contracts). The rates typically only poorly reflect the true cost of delivering power such as the cost differences inherent in the supply during peak and off-peak periods. A low-load factor customer who is paying the same rates as a high-load factor customer might find that they cover the costs of generating electricity themselves. This motivation should be reduced as electricity becomes deregulated and time-of-day pricing becomes more prevalent.

Third, and a key reason, the industry restructuring and increased competition will lead to the functional unbundling of services consisting of generation , transmission, distribution and ancillary services. This unbundling will be driven by the associated need to learn more about how much it costs to supply individual customer groups with differing load characteristics and the consequent setting of rates to better reflect these costs. This unbundling will reflect peak/off-peak periods, fixed/variable costs, geographic location variations, and reliability/power quality standards. Over time these cost differences should be translated into rates that provide appropriate market signals to prevent uneconomic bypass of the utility by customers. "Unbundling of costs will be inevitable in a competitive utility industry and will play an important role in defining the markets for distributed resources. While such unbundling will make it difficult for some distributed resource applications (as discussed above), unbundling will, at the same time, become the driving force in creating new DR applications."[11]

Fourth, one of the more significant potentials for distributed generation exists in applications with substantial transmission and distribution cost savings. Although this is really a specific case of the third reason above (a market created by the unbundling of T&D costs), it is highlighted because of its significance. Much of this market is based upon T&D savings that are created for peak-load or peak-shaving applications. But there are at least three other reasons why distributed peak-load applications are likely to dominate. First, since may utilities are increasingly short on peak-load resources, distributed peak-load resources may fit well into the utilities' resource requirements. Second, distributed resources may have a significant cost advantage versus the expansion of some localized T&D capacity or where the expansion potential is limited due to environmental or political reasons. Third, distributed resources will be an attractive measure to maintain or increase reliability and power quality for some customers.

A significant current and potential market exists for distributed generation based primarily on the availability of unique, on-site advantages that lower costs (for example, thermal energy) and on the unbundling of the various costs for generation, transmission, distribution, and ancillary services. This helps to focus our discussion. The next section will look at distributed generation from a somewhat different perspective, with the underlying idea of how to approach the modeling of distributed generation in the context of the NEMS or POEMS. The modeling of distributed generation will be difficult and there may be two key questions that also relate to the modeling and that are described in:

> The issue of distributed generation ... "is a complex subject from at least two different points of view. First, the basic economics, that is to say investment appraisal is not straightforward. This comes from the fact that Distributed Resources are only competitive at the local level, that is after a complex set of transmission and distribution costs have been incurred. Formalizing this bottom line competition in an investment appraisal tool is a formidable challenge. Second this competitiveness is heavily influenced by the restructuring process which is at this stage still in development. Specifically, who will decide investments in DR and under which pricing environment remains largely an open question."[12]

## Matrix of Market Cells Describing Distributed Generation

In the discussion above we tried to put some kind of boundaries, as weak as they may be, around what we consider to be distributed generation. However, all of that territory we defined encompasses a wide variety of players ("actors") and a wide variety of activities defined largely by motive, incentive, or purpose ("factors"). For the purposes of illustration and for cogent discussion the market for distributed generation can be segmented into a matrix of market cells that identify the actors (utilities, distribution companies, third parties, residential customers, commercial customers, industrial customers, etc.) versus the factors which are their incentives or motivations. An attempt at defining a group of these market cells is shown in Table 2.

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[11] ibid.

[12] *Introduction*, Smeers, Yves and Adonis Yatchew, in *A Special Issue of the Energy Journal, Distributed Resources: Toward a New Paradigm of the Electricity Business*, 1977.

A good deal of the discussion of distributed generation, particularly with respect to the modeling of distributed generation, gets sidetracked on questions relating to the various market segments. This matrix is an attempt to clearly delineate those market segments or market cells. There still remains a good deal of overlap between the market cells and the definitions of the actors and factors still are not precise, but this provides a very good framework for discussion and for a path to modeling distributed generation.

## Qualifications Relating to the Drawing of Market Cells

The discussion of distributed generation in terms of market cells is by no means perfect. There are still a number of issues that are not completely addressed within this context. Some of these are:

*Fine Line and Overlap Among the Market Cells*. There can be a fine line between some of the market cells and there can be a good deal of overlap among them. For example, although the distinction may be fairly clear between each end user (residential, commercial, and industrial) and between the group of the end users and the other actors, it is less clear where the line is between the generator and the distributor and the third-party, particularly as the electricity markets continue their structural evolution.

*Third Dimension to the Market Cells*. One could consider that there is a third dimension to the definition of the market cells consisting of the types of technologies. This might be particularly true with respect to their broader categories of generation technologies (with subcategories of renewables versus non-renewables) versus storage technologies versus demand side management technologies. Some of the technologies relate very closely to the various actors and some to the various factors and add another layer of dimensionality. To keep things more manageable we will not consider only the two dimensions and technologies will be discussed more thoroughly later.

*Questions Relating to Competition and Market Structure*. Much of the discussion of distributed generation and its potential depends upon the answers to questions about the amount of competition in T&D, the unbundling of costs for T&D and its pricing (how it is passed through to consumers), the emergence of marginal cost pricing, the relationship between T&D and generation and generators, the niches for third-parties, etc. All of these questions have an impact upon what is in each market cell. The only way that these can be handled is to provide a context for the discussion of each of market cells.

**Table 2. Players (Actors) and Incentives (Factors) Defining Distributed Generation Markets**

| | **Actors in the Distributed Generation Market** | | | | | |
|---|---|---|---|---|---|---|
| | A. Generators | B. Distribution Companies | C. Third Parties | D. Residential Customers | E. Commercial Customers | F. Industrial Customers |
| **Factors/Incentives for Distributed Generation** | | | | | | |
| 1. Spatial Issues (Small areas, T&D, etc.) | | | | | | |
| 2. Temporal Issues (Time-of-day load shapes, etc.) | | | | | | |
| 3. Economic Incentive Issues (Subsidies, Tax Credits, etc.) | | | | | | |
| 4. Environmental Issues | | | | | | |
| 5. Niche Markets (Non-Economically Driven) | | | | | | |
| 6. Grid Connection Issues | | | | | | |
| 7. Steam/Heat Availability (Cogeneration) | | | | | | |
| 8. Byproduct Availability | | | | | | |
| 9. Opportunities for Demand Side Management | | | | | | |

## Spatial Load Issues

Spatial load issues are one of the primary drivers for much of the interest in distributed generation. This has to do with the fact that electric power distribution areas are often met with a wide variety of loads that vary among the smaller areas within that distribution area. This is coupled with the high costs and inherent uncertainty of building new transmission and distribution capacity. "Electric power delivery is among the most capital intensive of businesses. The required transmission and distribution (T&D) facilities need land for rights of way and substation sites, power equipment for transmission, distribution, protection and control, and extensive construction labor, all involving considerable expense. Arrangements for new or expanded facilities normally require several years, meaning that a utility usually must plan at least five, and sometimes as far as ten, years ahead."[13]

In a more competitive, non-cost-of-service market it may be to the advantage of the power provider to build new distributed generation resources rather than to pay for an expansion or upgrade to the T&D infrastructure. Depending upon the costs and the risks involved, distributed generation may be more cost effective. "In the past, utilities were mainly concerned with the generation and bulk transmission systems. In recent years, however, the ratio of local transmission and distribution (T&D) expenditures to total capital expenditures has increased dramatically."[14] However, some of this may be driven more by declines in new generation capacity (to IPPs) and not by increases in T&D expenditures.

Although the electric utility industry in this country originally began on a distributed generation model, it has been characterized for many years now as satisfying customer demand through large central power station generation. The industry has been vertically integrated so that the same (in many cases) central utility distributed the electricity through an extensive transmission and distribution (T&D) network, sized to meet system-wide demand, rather than local peak demand. System-wide demand increases were satisfied by generating more electricity and building more T&D capacity and small area demand increases were satisfied by building more T&D capacity.[15] This demand might be satisfied in many cases by lower cost distributed generation technologies. "Distributed generation and targeted demand side management programs offer electric utilities alternatives to large transmission and distribution (T&D) system capacity investments."[16] This is further elaborated by:

> "Besides the traditional concerns of the electric generation industry (e.g., meeting generation needs, ensuring adequate transmission facilities, etc.), some new concerns are gaining greater importance.

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[13] *Spatial Electric Load Forecasting*, H. Lee Willis, p. 5, 1996, Marcel Dekker, Inc., New York.

[14] *Marginal Capacity Costs of Electricity Distribution and Demand for Distributed Generation*, Woo, Chi-Keung, Debra Lloyd-Zannetti, Ren Orans, Brian Horii, and Grayson Heffner, in *The Energy Journal*, 1995, Vol. 16, No. 2.

[15] *Identifying Distributed Generation and Demand Side Management Investment Opportunities*, Thomas E. Hoff, in *The Energy Journal*, 1996. Hoff notes that "DG and DSM are so closely related that Bailey et. al. (1993) and others have used DG technologies as DSM measures." We consider DSM to be one facet of distributed generation in this paper.

[16] ibid.

> These include: (1) the growing strains on the distribution network and the increase in service interruptions from growth in electricity demand; (2) the growing need for improved power quality to meet the requirements of advanced energy using systems; and (3) increased land use restrictions which make it difficult to attain right-of-ways for transmission lines and to site new generating capacity. ... A potential beneficiary of the changes taking place in the electric industry is distributed generation."[17]

*Variance in Marginal Distribution Capacity Costs*. It has been shown by several researchers that the marginal distribution capacity costs for electricity can vary widely by area, both across utilities and within single utility territories. The marginal distribution capacity cost (MDCC) is defined as the savings in present value (PV) of an electricity demand reduction of 1 kw in local area demand.[18] The idea behind the measurement of MDCC is to estimate the savings available in deferring the expansion of a small segment of the distribution system in a specific planning area. These savings can then be compared to the alternative costs of installing distributed generation resources (including demand side management options). If there were no other constraints or frictions, one would install distributed generation resources to satisfy load in all small planning areas in which the cost of the MDCC is greater than the cost of the distributed generation. In some sense, the distribution of the MDCCs across the utility planning area defines the demand for distributed generation.

The question about how much the MDCC varies with a utility's territory remains. The amount of variance and the range of high MDCCs determines how much potential there is for distributed generation due to the spatial load costs. A key study by Woo, et. al., measured the MDCCs with the utility planning areas for PG&E California and for PSI Indiana.[19] Table 3 shows some of the range of costs from that study.

**Table 3. Descriptive Statistics for 1994 MDCC ($/kW) by Utility**
(from Woo, Chi-Keung, et. al.)

| Utility | Number of Areas | % Areas with $0/kW | 1st Quartile Cost | Median Cost | 3rd Quartile Cost | 90th Percentile Cost | Max. Cost | Mean Cost | Standard Deviation |
|---|---|---|---|---|---|---|---|---|---|
| **PG&E** | 201 | 19% | $166 | $240 | $303 | $392 | $1,173 | $230 | $156 |
| **PSI** | 152 | 73% | $0 | $0 | $28 | $197 | $1,040 | $64 | $169 |

The table clearly shows that there is a wide variance of costs within a utility's planning area. In the 201 planning areas for PG&E the costs range from $0 to $1,173, with a mean of $230 and a standard deviation of $156. In the 152 planning areas for PSI the costs range from $0 to $1,040, with a mean of $64 and a standard deviation of $169. The spread of costs for PSI is about as wide as for PG&E, but many more of

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[17] *Baseline 1999*, Gas Resource Institute, 1999, Washington, DC.

[18] *Marginal Capacity Costs of Electricity Distribution and Demand for Distributed Generation*, Woo, Chi-Keung, Debra Lloyd-Zannetti, Ren Orans, Brian Horii, and Grayson Heffner, in *The Energy Journal*, 1995, Vol. 16, No. 2.

[19] ibid.

their planning areas have very low costs as the distribution is skewed to the lower end of costs. PG&E has a less skewed distribution, putting the costs for many of the planning areas at a much higher level. The higher costs in so many planning areas for PG&E is probably due to distribution network congestion in an urban environment, and the high costs of expanding or upgrading the distribution network.

These large variances and the numbers of planning areas having high MDCCs suggests that there might be significant distributed generation opportunities. In a typical system-wide analysis of the same utilities, the average cost would be the subject. In an analysis of that type the average costs in the two cases of $230 and $64 might lead to the conclusion that distributed generation is not cost-effective if implemented on a system-wide basis in either of the two utilities. The result of looking at the distribution of the MDCCs leads to a different conclusion, that there are significant opportunities. The authors state that "If a DG device has a net life-cycle capacity cost of $300/kW, in 1994 there are approximately 5,300 MW of cost-effective DG applications in PG&E's territory." Their conclusion is that:

> "This analysis yields two major findings. First, MDCCs vary by utility and over time and it is this area- and time-specific nature of MDCCs that drives the DG demand. Second, the demand for DG confirms that a system-wide implementation of DG is generally not cost-effective and DG should only be targeted at areas with high MDCCs that are caused by significant distribution investments in areas with moderate growth in electricity demand."[20]

Note that there are at least two significant comments to be made about this analysis. First, distributed generation capacity built to reduce MDCC in any one small planning area has an immediate complementary effect on the MDCC in all the neighboring (close by) planning areas. This is because any electricity that is put into the grid is freely available everywhere else on the grid (within the constraints of the grid). This complicates the measurement of the true value of distributed generation and the assessment of the risks. Second, the measurement of MDCC is time-varying, which further complicates the measurement of the true value of distributed generation.

*Market Cells Applying to Spatial Load Issues*. Most of the motivation for distributed generation that is due to spatial load issues applies to utilities or distribution companies who are investing to defer costs associated with distribution bottlenecks. This would generally require that the utility or distribution company would be aware of these marginal costs and would be acting upon them. On a contract basis the motivation might also apply to third parties. This motivation would apply to final consumers only in a different market organization, basically if the distribution costs were passed through to final consumers (through distribution cost unbundling and then marginal cost pricing).

## Temporal Load Issues

Temporal loads are those that vary over time whether by time-of-day or by season. The issues associated with temporal loads can be closely related to the spatial load issues discussed above, especially when they impact upon transmission bottlenecks. But under marginal cost pricing, temporal load issues provide other motivations, also.

*Transmission Bottlenecks*. When the variances in time-of-day or seasonal loads cause transmission

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[20] ibid.

bottlenecks, then the motivations and solutions are the same as discussed above under the spatial load issues. The effect is to increase the MDCC and provide a greater opportunity for distributed generation in place of investments in T&D capacity. As noted above, this motivation applies primarily to utilities and distribution companies.

*Time-of-Day Pricing*. When electricity is priced based upon time-of-day loads, end-use customers can move consumption from peak periods to non-peak periods or they can invest in distributed generation if it can provide the electricity for a lower cost. Since the peak periods occur for only a small period of the time, any investment in distributed generation will satisfy the load for only a short period of time. The opportunity to sell the electricity back to the grid will increase the economic incentives for distributed generation. The motivation for distributed generation to shave the peak load applies primarily to end use customers, if the prices for electricity are time-of-day prices. The motivation probably applies most strongly to industrial customers, next to commercial customers, and least to residential customers (although the time-of-day pricing variation and the level of average price might apply in the opposite order). The motivation also applies to utilities and distribution companies to the extent that the customer is able to shift his load or to the extent that the customer can find an alternative source for the electricity. Third parties might also be motivated to find a niche due to peak shaving.

### Economic Incentive (Pricing/Costs/Market Organization) Issues

Clearly this is a cross-cutting category and is at the core of the motivation behind almost all the other issues. Some of the considerations include:

*Basic Cost Considerations*. The overriding idea is that if the cost for distributed generation is less than the cost of electricity then an investment might be made in distributed generation. This applies across the board and forms the basis for almost all the other motivating factors. But in reality there are a number of constraints and imperfections that cause this not to happen. For example, a key market imperfection has been that electric utilities do not unbundle the cost of transmission and distribution and that their revenues are based upon cost-of-service regulation and not on perfect competition.

Other economic issues relating to markets and their organization include the extent of deregulation and competitiveness of the transmission and distribution sectors, the unbundling of costs to the transmission and distribution and ancillary services sectors, cost-of-service versus marginal cost pricing, grid access, renewable portfolio standards, and the evolution of various market players including generators, distribution companies, POOLCOs, energy service companies, independent power producers, and others. Economic issues relating to price and cost signals in markets include various subsidies, incentives, tax credits, pass-throughs, green pricing, grid pricing through net metering versus other methods, etc.

### Environmental Issues

The environmental issues relate principally to questions about siting of distributed generation resources, incentives for benign technologies which either reduce emissions or are renewable technologies, incentives for general usage of distributed generation in order to provide a net reduction in overall emissions (central power station versus distributed generation), etc.

### Niche Markets

There are niche markets for distributed generation, primarily those in which consumers are investing in DG for a motive other than a cost motive. There are many consumers who are willing to pay higher costs for electricity so that they can use renewables for their power generation. There are those consumers who are willing to pay higher costs so that they are self-sufficient and independent of the power company. These are real markets and are significant at a micro level, but do not add up to large amounts of generation.

### Grid Connection Issues

The FERC Orders 888 and 889 in 1996 enabled a much greater access to the electric power grid. There still remain key questions relating to how sales to the grid will be priced, how they can be regulated with respect to power quality standards, how they affect the overall reliability and safety of the grid, etc. The pricing is the only real issue that impacts upon distributed generation, with the other issues being technical in nature, requiring engineering solutions and impacting upon distributed generation only if there is ultimately a significant cost issue.

*Pricing*. This has been a difficult issue for a number of years. Typically the price that is paid for distributed generation that is connected to the grid has been the alternative central station generation cost. Legislation has been proposed to change the pricing to net metering, meaning that the distributed generation is sold to the grid at the retail price. This clearly provides more opportunity for distributed generation as the capacity that is not needed for shaving peak loads can be sold for a higher price than otherwise.

*Power Quality and Reliability*. There has been some concern that the general availability of the grid to all distributed generators will cause problems with power quality and reliability. The first deals with the need to assure that the grid will not be corrupted by faulty or poorly designed equipment that is connected to it. This is an issue of setting standards and regulation of the equipment that is connected and should be easily resolved without adding any significant cost to distributed generation. The second deals with the ability of the overall system to guarantee the availability of sufficient electric power capacity when much of the capacity is dispersed and not under central control. This is a more difficult issue but should not impact significantly on the cost for distributed generation.

### Steam/Heat Requirements and Byproduct Availability

A classic case of distributed generation is cogeneration and the use of byproducts for generation by industrial and commercial customers. In the industrial sector there are a number of opportunities for generation of electricity with the steam that is already required for various processes. This is also an opportunity in some segments of the commercial sector, especially in conjunction with district services. The joint generation of electricity and steam and/or the use of otherwise wasted steam can increase the effective conversion efficiency and allow the cost for electricity generation to be much lower than they would be otherwise. Also, in the industrial sector there are some industries that have by products that can be used to fuel generation of electricity. The most significant of these is in the paper industry where much electricity is generated by the biomass byproducts for a much lower cost than otherwise.

### Demand Side Management Opportunities

Some commentators put demand side management (DSM) into a separate category, but in this paper it is considered as another form of distributed generation. Its traditional motivation was for utilities to reduce (shave) or move the peak loads of customers so that they could defer the construction of much more expensive generation capacity.  This motivation still applies for generators and distribution companies, although it may shift more from generators to distribution companies as the generation and distribution functions are separated.  The motivation may also apply to end use customers as they are introduced to time-of-day pricing.  Third parties might also have the motive to move into this market.

### Distributed Generation Technologies

Distributed generation technologies have been gaining an increasing amount of interest largely due to the electricity industry restructuring and the consequent changes in the level of competition and in pricing structures.  However, distributed generation technologies have also been gaining interest because of the increasing and changing slate of smaller, more accessible, modular equipment that is becoming available, and because of declining costs and increasing efficiencies.

A wide variety of technologies are available for use in distributed generation.  The following is a list of some of the key technologies, grouped into categories.  The technologies in the list are more completely characterized and described in *Renewable Energy Technology Characterizations*[21] and in *Characterization of Distributed Resource Technologies*[22].

*Renewable Technologies*
  Landfill Gas
  Animal Waste
  Biomass Generation Systems (Gasification, Direct-Fired, Co-Fired)
  Municipal Solid Waste (MSW)
  Photovoltaic Systems (Residential, Utility-Scale Flat-Plate Thin Film, Concentrators)
  Wind Turbine Systems (Advanced Horizontal Axis, Hybrid Wind/Diesel)
  Solar Thermal Systems (Residential, Power Tower, Parabolic Trough, Dish Engine)
  Geothermal Systems (Hydrothermal, Hot Dry Rock)

*Non-Renewable Technologies*
  Mini-Turbines and Engines (less than 20kW to 50 MW)
  Combustion Turbines
  Steam Turbines
  Reciprocating Engines
  Fuel Cells
  Coalbed Methane

*Energy Storage Technologies*
  Batteries
  Thermal Energy Storage
  Flywheels

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[21] *Renewable Energy Technology Characterizations*, TR-109496, Office of Utility Technologies, EE, USDOE and Electric Power Research Institute, December 1997.

[22] *Characterization of Distributed Resource Technologies*, prepared by The Cadmus Group, SAIC, and OnLocation, July 1997.

Superconducting Magnetic Energy Storage (SMES)
Supercapacitors
Hydrogen

*Demand-Side Management Technologies*
High Efficiency Heating, Cooling, Ventilation, Water Heating Technology
Active Solar Heating and Cooling Technology
High Efficiency Lighting and Ballasts
Energy Efficient Motors and Motor Systems
Energy Efficient Refrigeration
Building Envelope Technologies (Advanced Glazing, Insulation, Passive Solar)
Load Control Devices
Energy Management Systems (EMS)

## A Framework for Distributed Generation Modeling

As detailed earlier, on an average cost basis, few distributed generation technologies can compete with central power station generation. However, there may be greater opportunities for distributed generation when we deal with the distributions or variances in costs. These can be due to transmission and/or distribution small area bottlenecks, due to time-of-day load peaks, and due to some other smaller factors. There are also other opportunities for distributed generation when costs can be reduced by using already available thermal energy or other byproducts. Costs may also be reduced by explicit fiat or regulation (through incentives, subsidies, rebates, etc.), in order to satisfy a desired social or welfare goal. There are also niche markets for distributed generation where costs are not the primary consideration.

The framework for distributed generation, particularly with the perspective of modeling it, might be greatly summarized by the following:

The key, primary factors for motivating or driving distributed generation are:

- Availability of excess thermal energy or byproducts;

- Unbundling of various costs for generation, transmission, distribution, and ancillary services. This relates primarily to cost variances due to transmission and distribution system capacity and due to time-of-day loads.

There are other smaller opportunities for distributed generation due to unique cost structures, power reliability/quality, incentives, niche markets, etc.

The key actors fall into various categories. Electricity generation and distribution companies and third-parties would be primarily actors in the market having to do with cost variances. The extent of end use customers involvement in this market depends largely upon the degree of unbundling and how much of the costs are passed through. In general, the involvement would be most for industrial customers, next for commercial customers, and least for residential customers. End use customers would be primarily actors in the market having to do with availability of excess thermal or other resources. These are specific markets and involve various industrial and commercial customers. Table 4 provides a summary of the major factors and actors.

**Table 4. Major Factors for Distributed Generation**

| | Utility / Distribution Company / Third-Party | End Use Customers - Residential, Commercial, Industrial |
|---|---|---|
| Availability of excess thermal energy or byproducts. | Not particularly applicable. | Can reduce costs for cogeneration. Applies principally to industrial, next to commercial. |
| Local T&D capacity bottlenecks, plus time-of-day peak loads. | Major factor for DG. Allows the T&D infrastructure costs to be deferred. | Currently minor factor for DG. Importance in future depends upon degree of competition, pricing structure. |

The division of the actors into the two groups in the above table parallels the way that "cogeneration" has been separated for modeling in the NEMS into "traditional" and "non-traditional" categories. The traditional cogeneration has been that which is done by end users for direct consumption. The non-traditional cogeneration has been that which was done for the sole purpose of marketing electric power sales to the grid.

The key uncertainties associated with distributed generation are:

- How to formalize an investment appraisal for distributed generation when the competition is on a very localized level, after a complex set of transmission and distribution costs have been incurred.

- The competitiveness of distributed generation is heavily influenced by the ongoing restructuring process. The open question is who will decide investments in distributed generation and under what pricing environment.

## Decomposition of End Use Demand

### Residential Sector

The extent of direct investment in distributed generation in the residential sector would be expected to be low. The current amount of distributed generation is small enough that it is not significant in the regional NEMS model and is not counted. The residential sector consists of a large number of relatively small entities that would not ordinarily make the investments for distributed generation. Because the loads are fairly small, the distributed generation technologies would have to be very small in scale. Typically any investment that is made would be made on a small scale to supply electricity to the primary household with some small sales to the grid. Although electricity prices in the residential sector are much higher than in the other sectors and as a consequence make DG more attractive, the fuel costs are also much higher. Also, in the residential sector the cost of capital is general higher too, but in many cases some of the investment can be made in conjunction with a home loan. There are a number of significant niche markets, however, for users who are off the grid and need electric power and for users who desire to be independent from the grid or who desire to use renewable resources.  Some renewable technologies are particularly appropriate because of their potential small scale, but they are not generally purchased because of their high cost.  The residential sector has also been targeted with incentives, subsidies, and tax credits which can cause an increase in the penetration of DG.  The excess heat from some DG technologies can be captured and used to help defray costs for hot water heating and space heating in season but this is only a small factor.

The residential sector has a fairly peaked load shape, especially in the middle of the heating season and again in the middle of the cooling season.  The extent of the peakedness and the degree to which residential consumers face time-of-day loads in the future may be a factor in the use of distributed generation.

Most of the time, the residential sector consumers that are considered for distributed generation are owners of single family housing units because individual multi-family and mobile homes do not have the sites.  However, multi-family housing units in large buildings or communities might purchase distributed generation in a joint fashion, on a large scale.  In these cases the cost of capital should also be less.  This might also be true of single family and mobile home communities.

### Commercial Sector

The commercial sector has some incentive for investment in distributed generation and is structured in a fashion in which investments can be made and financed on a larger scale than for most of residential.  The primary incentive is that there are certain areas in the commercial sector in which excess thermal energy can be used for cogeneration.  One large source is in district services, but there are many other large-scale buildings or projects that use thermal energy that wouldn’t be classified strictly as district services.  Key among these are hospitals and education institutions, along with a host of others.  Hospitals also have a strong incentive to have high quality reliable power, with backup capability which might lead to distributed generation.

### Industrial Sector

The industrial sector is a long time generator of electricity, using cogeneration and byproducts.  The paper industry generates the largest amount of electricity through the use of waste biomass products.  It is expected that this would continue and in the future, as the technology becomes available there is a large capacity for generating electricity through black liquor gasification.  This would probably lead to greater sales to the grid.  Other electricity generation in the industrial sector is through cogeneration where steam requirements and electricity generation are met using the same technology creating much greater efficiencies.

# Preliminary Modeling of Distributed Generation in NEMS

The purpose of this section is to provide documentation for the forecasting of distributed generation (including cogeneration) in the NEMS demand models. This report documents the various algorithms explaining the manner in which they work and providing some examples, and noting some particular items of interest. However, this report does not attempt to be a critique of the models and their operation or to offer alternative algorithms.

## Residential Sector Distributed Generation

### Residential Model Introduction

The NEMS Residential Model has a primary level of disaggregation by nine Census divisions and three housing types (single family, multi-family, and mobile homes). The model considers energy consumption for a number of fuels in a wide variety of end uses, within an accounting scheme that takes explicit account of new and replacement capital stock both in housing and in energy-using equipment. The choice algorithms for the energy-using equipment are basically a logit-type formulation, with weights based upon a mix of present discounted value of various costs for competing equipment across general and specific categories of equipment.

Up to and through the Annual Energy Outlook (AEO) 1999, the NEMS residential model has not modeled distributed generation directly. However, some of the energy efficiency modeling might be considered to be a form of distributed generation. During 1999, in preparation for the AEO 2000 and other analyses, preliminary work has been done to add a new, technology-based distributed generation modeling routine to the residential model. All the work is preliminary and is in a testing stage and has not yet been finalized at the time this report is being written. Most of the information that is provided here has been shared with us by the NEMS modelers, but may have changed by the time this is read[23].

### Distributed Generation Modeling Background

The preliminary residential sector distributed generation algorithm has the potential to evaluate the three technologies of photovoltaics, fuel cells, and micro turbines. The input file represents all three of these technologies. However, micro turbines are in effect turned off (they have a 0 base capacity and a 0 number of hours of operation). Therefore, the algorithm (at this preliminary stage) relates primarily to photovoltaics and fuel cells.

The penetration of each technology is modeled in two separate categories consisting of exogenous penetration and endogenous penetration. The exogenous penetration consists of a fixed exogenous amount that is in an input file and is subsequently read in and directly implemented. The endogenous penetration is

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[23] This information is from communications with the NEMS buildings sectors modelers and from a Buildings Sector Working Group Meeting on June 24, 1999. As noted, the work described here is preliminary and may change as further work is done.

the subject of the model algorithm and its calculation is dependant upon a variety of variables including prices, costs, consumptions, and various parameters.

The algorithm and most inputs for both exogenous and endogenous penetration are detailed by census division and run year by year starting in 1998. The exogenous penetration amounts are numbers that could apply to any housing types, new or existing. The endogenous penetration is calculated as a rate (a fraction) and is applied to new single family homes only. Each technology is specified and used in the code over five "vintages" to represent its change over time. For example, the first vintage for photovoltaics covers the period 1993 through 1999 during which it is assumed that photovoltaics have an efficiency of 0.11 and a capital cost of $6569. The second vintage for photovotaics covers the period 2000 through 2006 during which it is assumed they have a better efficiency of 0.14 and a lower capital cost of $5887.

The endogenous penetration algorithm appears to operate year by year using three basic steps. In the first step, the model initializes a variety of variables such as the annual base Kwh output, and the annual base value of electricity saved. In the second step, the model does the financial calculations that determine the payback period for each technology, using a variety of price, cost, load, and economic data. In the third step the model determines the penetration rate for each of the technologies (based upon the payback period), applies it to the number of new single family homes, adds in exogenous penetration numbers and provides the results back to the model.

**Base Values and Initialization of Variables**

In each forecast year, for each Census division, and for each of the three technologies, a variety of initial values are set up for later use. These include things such as:

- Price of the distributed generation. This is the price for electricity sold to the grid. For photovoltaics this is made equal to the airconditioning price[24] and for other technologies this is the airconditioning price with a net meter adjustment of 0.5.
- Overall capital cost in the base year. This is the equipment cost per kw plus the installation cost per kw times the base equipment output in kw.
- Maintenance cost in the base year. This is the maintenance cost per kw times the base equipment output in kw. It is assumed there is no maintenance cost for solar.
- Annual base kwh supplied by the base sized equipment. In the case of solar this takes into account the efficiency, the insolation (by region), the loss factor, the physical size of the array, and the base equipment output in kw. In the case of the other technologies this takes into account the operating hours, the availability, the loss factor, and the base equipment output in kw.
- Excess kwh. This measures how much more electricity is generated by the equipment than what is used in the average house. This is positive when there is an excess amount generated and sold to the grid, and this is negative otherwise.
- Value of electricity saved in the base year. This is the value of the electricity that is not otherwise purchased plus the value of any electricity that might be sold to the grid.
- Gas input btu. This is the amount of natural gas used to fuel the technology. This does not apply to solar.

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[24] The residential model uses separate prices for most of the residential end uses. These are provided by the electricity model and are meant to represent the effect of time-of-day pricing.

- Waste heat btu. This is the amount of waste heat generated by the technology that could be applied to water heating. This does not apply to solar.
- Water heating consumption. This is the average amount of water heating per house (unit energy consumption) that could potentially be displaced by the technology's waste heat.
- Fuel cost in the base year. This is the net cost of the fuel that is used by the technology. This does not apply to solar.

## Financial Calculations

In each forecast year, for each Census division, and for each of the three technologies, financial calculations are made over the lifetime of the equipment in order to determine the payback period for that equipment. The model performs these calculations by simulating the year-to-year transactions that would occur over a 30-year period (this is beyond the equipment lifetime). The more significant transactions that are simulated include:

- Down payment and annual payment. The down payment is an assumed percent of the overall equipment capital cost. The annual payment is based upon the total loan, the term of the loan, and the interest rate for the loan.
- Principal, interest, loan balance. In each simulation year, these are based upon the previous year's loan balance and the interest rate.
- Tax credit and tax deduction. The tax credit is an assumed amount that applies in one year. In each simulation year the tax deduction is based upon an assumed tax rate and the amount of interest paid and the amount of equipment depreciation (if this applies) plus the tax credit.
- Fuel costs and maintenance costs. In each simulation year these are the base year amounts augmented by the amount of assumed inflation over the years.
- Annual electricity generation and annual value of electricity saved. In each simulation year these are the base year amounts degraded by the amount of assumed degradation over the years. The value of electricity saved is also augmented by the amount of assumed inflation over the years.
- Net cash flow and cumulative net cash flow. In each simulation year, the net cash flow is the value of electricity saved in each year, plus the amount of the tax deduction, minus the payments (outlays), minus the fuel cost, minus the maintenance cost. In each simulation year, the cumulative net cash flow is the sum of the net cash flows in the current and all previous years.

The objective of the financial calculations is to come up with a payback period for each technology. The cumulative net cash flow is investigated in each year in order to determine the payback period. The payback period is the number of years until the cumulative net cash flow becomes a positive amount (and stays positive).

## Technology Penetration

In each forecast year, for each Census division, and for each of the three technologies, an (endogenous) penetration rate is calculated and assumed to apply to new single family houses. The technology penetration is calculated based upon the payback period, the forecast year, and assumed coefficients. There are two steps to its calculation.

The first step is to calculate a maximum possible penetration rate using the payback period and an assumed coefficient. This is given by the inverse of the payback period times the coefficient. The input coefficient is 0.3, so if the payback period were 5 years, then the maximum penetration rate would be 0.2 * 0.3 or 0.06.

The second step is to calculate the actual penetration rate using the maximum penetration rate, the payback period, the number of years since the technology was introduced in the model, and an assumed coefficient.

$$\text{PenRate} = \text{MaxPenRate} - 1 / ( ( 1 / \text{MaxPenRate} ) + \exp ( \text{Alpha} * ( \text{YearsAvail} - \text{Payback} ) ) ).$$

This endogenous penetration rate in each year is multiplied by the number of new single family homes to calculate the number of housing units using each technology that is determined endogenously. The model also adds a number of housing units using each technology that is determined exogenously. The sum of these two is the total number of housing units using each technology forecasted by the model.

### Integration with Residential Model and other NEMS Modules

In each forecast year, for each Census division, and for each of the three technologies, the number of housing units using each technology is used to calculate various results that are used in the residential model or in other NEMS modules.

- Cumulative units and cumulative electricity generation. The number of housing units using each technology are summed over time to get the number of cumulative units. Corresponding to this the number of housing units using each technology are multiplied times the annual generation of electricity for each technology to get the electricity generation. This is summed over time to get the cumulative electricity generation.
- Cumulative own electricity use. All electricity generated up to the average unit electricity consumption is for own use. Any generation above this amount is sold to the grid. This can be summed over time to get the cumulative own electricity use.
- Cumulative gas usage and cumulative water heating btus. The number of housing units using each technology times the gas consumption of the technology summed over time is the cumulative gas usage. The number of housing units using each technology times the water heating displaced by the technology summed over time is the cumulative water heating displaced.
- Annual capital investment costs. The number of housing units using each technology times the capital cost for that technology is the annual capital investment cost.

### Additional Comments

The algorithm is in a very preliminary stage, so these are comments relating only to this version. As noted above the base capacity and the number of hours of operation for micro turbines are 0, in effect turning them off so they are not being modeled. As it turns out, the economics in a typical base case for both photovoltaics and fuel cells are such that the endogenous penetration algorithm does not allow any penetration for them. (Basically the capital costs are too high for them to experience any penetration, especially for fuel cells.) However, photovoltaics do have exogenous penetration, so that the ultimate forecast for photovoltaics comes solely from the exogenous penetration. Fuel cells do not have an exogenous penetration (other than a nominal amount of 1 per region), so that the ultimate forecast for fuel cells is zero.

Table 8 shows a sample set of financial calculations simulated over a 30-year period for photovolatic technology in the forecast year 2000 using typical values from the input files. It is clear from the table that the cost of the photovoltaic technology so exceeds the resulting value of energy savings that there is never a period in which it is paid back. In this case the payback period is 30 years or more and the consequence is that there is only a very tiny penetration.

Table 9 shows a sample set of resulting penetration rates for different forecast years and for different payback periods. Obviously, the larger the payback period in the same forecast year, the smaller the maximum and actual penetration. The further out the forecast year, the greater is the resulting penetration for the same payback period.

Table 10 shows some summarized results from a run of the distributed generation algorithm in the residential model using the AEO99 base case.

Table 11 shows some very preliminary key inputs to the residential sector distributed generation.

**Table 8. Example of Typical Financial Calculations for Residential Photovoltaics**

| Simulation Year | Tax Credit | Outlay | Interest Amount | Principal | Loan Balance | Tax Deduction | Fuel Cost | Maintenance Cost | Value of Energy Save | Net Cash Flow | Cumulative Net Flow | Kwh Generation |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 0.00 | 1727.00 | 0.00 | 0.00 | 15543.00 | 0.00 | 0.00 | 0.00 | 0.00 | -1727.00 | -1727.00 | 0.00 |
| 2 | 0.00 | 1467.15 | 1088.01 | 379.14 | 15163.86 | 0.00 | 0.00 | 0.00 | 385.00 | -1082.15 | -2809.15 | 4871.90 |
| 3 | 0.00 | 1467.15 | 1061.47 | 405.68 | 14758.18 | 369.92 | 0.00 | 0.00 | 392.58 | -704.64 | -3513.79 | 4823.18 |
| 4 | 0.00 | 1467.15 | 1033.07 | 434.08 | 14324.11 | 360.90 | 0.00 | 0.00 | 400.32 | -705.93 | -4219.72 | 4774.95 |
| 5 | 0.00 | 1467.15 | 1002.69 | 464.46 | 13859.64 | 351.24 | 0.00 | 0.00 | 408.20 | -707.70 | -4927.42 | 4727.20 |
| 6 | 0.00 | 1467.15 | 970.18 | 496.97 | 13362.67 | 340.91 | 0.00 | 0.00 | 416.25 | -709.99 | -5637.41 | 4679.93 |
| 7 | 0.00 | 1467.15 | 935.39 | 531.76 | 12830.91 | 329.86 | 0.00 | 0.00 | 424.45 | -712.84 | -6350.25 | 4633.13 |
| 8 | 0.00 | 1467.15 | 898.16 | 568.99 | 12261.92 | 318.03 | 0.00 | 0.00 | 432.81 | -716.31 | -7066.56 | 4586.80 |
| 9 | 0.00 | 1467.15 | 858.33 | 608.81 | 11653.11 | 305.38 | 0.00 | 0.00 | 441.33 | -720.44 | -7787.00 | 4540.93 |
| 10 | 0.00 | 1467.15 | 815.72 | 651.43 | 11001.67 | 291.83 | 0.00 | 0.00 | 450.03 | -725.29 | -8512.29 | 4495.52 |
| 11 | 0.00 | 1467.15 | 770.12 | 697.03 | 10304.64 | 277.34 | 0.00 | 0.00 | 458.89 | -730.91 | -9243.20 | 4450.56 |
| 12 | 0.00 | 1467.15 | 721.32 | 745.82 | 9558.82 | 261.84 | 0.00 | 0.00 | 467.93 | -737.38 | -9980.58 | 4406.06 |
| 13 | 0.00 | 1467.15 | 669.12 | 798.03 | 8760.79 | 245.25 | 0.00 | 0.00 | 477.15 | -744.75 | -10725.32 | 4362.00 |
| 14 | 0.00 | 1467.15 | 613.26 | 853.89 | 7906.89 | 227.50 | 0.00 | 0.00 | 486.55 | -753.10 | -11478.42 | 4318.38 |
| 15 | 0.00 | 1467.15 | 553.48 | 913.67 | 6993.23 | 208.51 | 0.00 | 0.00 | 496.14 | -762.50 | -12240.92 | 4275.19 |
| 16 | 0.00 | 1467.15 | 489.53 | 977.62 | 6015.60 | 188.18 | 0.00 | 0.00 | 505.91 | -773.05 | -13013.98 | 4232.44 |
| 17 | 0.00 | 1467.15 | 421.09 | 1046.06 | 4969.54 | 166.44 | 0.00 | 0.00 | 515.88 | -784.83 | -13798.81 | 4190.12 |
| 18 | 0.00 | 1467.15 | 347.87 | 1119.28 | 3850.26 | 143.17 | 0.00 | 0.00 | 526.04 | -797.94 | -14596.75 | 4148.22 |
| 19 | 0.00 | 1467.15 | 269.52 | 1197.63 | 2652.63 | 118.28 | 0.00 | 0.00 | 536.40 | -812.47 | -15409.22 | 4106.73 |
| 20 | 0.00 | 1467.15 | 185.68 | 1281.46 | 1371.17 | 91.64 | 0.00 | 0.00 | 546.97 | -828.54 | -16237.76 | 4065.67 |
| 21 | 0.00 | 1467.15 | 95.98 | 1371.17 | -0.00 | 63.13 | 0.00 | 0.00 | 557.75 | -846.27 | -17084.03 | 4025.01 |
| 22 | 0.00 | 0.00 | 0.00 | 0.00 | -0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | -17084.03 | 0.00 |
| 23 | 0.00 | 0.00 | 0.00 | 0.00 | -0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | -17084.03 | 0.00 |
| 24 | 0.00 | 0.00 | 0.00 | 0.00 | -0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | -17084.03 | 0.00 |
| 25 | 0.00 | 0.00 | 0.00 | 0.00 | -0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | -17084.03 | 0.00 |
| 26 | 0.00 | 0.00 | 0.00 | 0.00 | -0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | -17084.03 | 0.00 |
| 27 | 0.00 | 0.00 | 0.00 | 0.00 | -0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | -17084.03 | 0.00 |
| 28 | 0.00 | 0.00 | 0.00 | 0.00 | -0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | -17084.03 | 0.00 |
| 29 | 0.00 | 0.00 | 0.00 | 0.00 | -0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | -17084.03 | 0.00 |
| 30 | 0.00 | 0.00 | 0.00 | 0.00 | -0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | -17084.03 | 0.00 |

Note: This is a example table created in a spreadsheet, using approximate data and does not directly represent a specific exercise.

**Table 9. Examples of Penetration Rates for Different Years and Payback Periods**

| Current Year | 2010 | 2010 | | 2015 | 2015 |
|---|---|---|---|---|---|
| Years Past 1998 | 12 | 12 | | 17 | 17 |
| Payback Period | 8 | 2 | | 8 | 2 |
| | | | | | |
| Penetration Parameter | 0.3 | 0.3 | | 0.3 | 0.3 |
| Maximum Penetration | 0.0375 | 0.1500 | | 0.0375 | 0.1500 |
| | | | | | |
| Alpha Coefficient | 0.7 | 0.7 | | 0.7 | 0.7 |
| Actual Penetration | 0.0143 | 0.1491 | | 0.0357 | 0.1500 |

Note: This is an example table and does not directly represent a specific exercise.

**Table 10. Overall National Results of a Distributed Generation Model Run (Preliminary)**
(These results are from a standalone AEO99 residential model run using the very preliminary distributed generation routine and input file.)

```
                             1998      2000      2010      2020
Houses added, SF            1.238     1.149     1.196     1.190
New after 1990, SF          5.756     8.022    19.145    30.036
Existing from 1990, SF     65.352    64.778    61.984    59.310
Total Houses, SF           71.108    72.800    81.129    89.346
Total Houses All Types    102.613   105.013   117.480   130.014
Photovoltaics
  Tech Costs              19439.8   17270.0   13560.3   11767.3
  Tech Average Kwh         4863.9    4871.9    4824.8    4836.6
  Tech Savings Value        393.8     385.0     368.4     341.3
  PayBack Years              29.0      29.0      29.0      29.0
  Tech Penetration           .000      .000      .000      .000
  Endog-This Year            .000      .000      .000      .001
  Exog-This Year            8.115     7.813    11.341      .000
  Total-This Year           8.115     7.813    11.341      .001
  Endog-Cumulative           .000      .000      .000      .002
  Exog-Cumulative           8.115    23.637   120.419   120.419
  Total-Cumulative          8.115    23.637   120.419   120.420
Fuel Cells
  Tech Costs              35875.0   35875.0   16975.0   12075.0
  Tech Average Kwh        50008.0   50008.0   50008.0   50008.0
  Tech Savings Value       1228.8    1196.8    1148.5    1061.8
  PayBack Years              29.0      29.0      29.0      29.0
  Tech Penetration           .000      .000      .000      .000
  Endog-This Year            .000      .000      .000      .001
  Exog-This Year             .000      .009      .000      .000
  Total-This Year            .000      .009      .000      .001
  Endog-Cumulative           .000      .000      .000      .002
  Exog-Cumulative            .000      .009      .009      .009
  Total-Cumulative           .000      .009      .009      .011
```

## Table 11. Key Technology Inputs to Residential Distributed Generation

(These are examples from a very preliminary distributed generation input file.)

```
Penetration Function Parameters
0.7   0.3

                 Tech1   Tech2   Tech3
System kw         2.75     7.0     0.0
Annual Oper Hrs   0.      8000.    000.

Net Meter Adjusts by Census Division
   Tech1   Tech2   Tech3
      1.      .5      .5

Solar Insolation Values
136.    New England, Boston
137.    Middle Atlantic, New York
138.    East North Central, Detroit
172.    West North Central, Omaha
196.    South Atlantic,Miami
161.    East South Central, Birmingham
180.    West South Central, Dallas
235.    Mountain, Albuquerque
168.    Pacific, Great Falls

Combined Federal and State Tax Rate, DownPayPct, Interest Rate, Loan Years, Inflation
   .34       .10   .07   20.  .03

            Fuel  First  Last         Loss  Degred.       Recv Install  Equip.   Maint       Tax Credit
Type        Type   Year  Year   Eff  Factor Factor  Life   Eff    Cost    Cost    Cost   Avail Percent Maximum
'Solar_PV'    0    1993  1999   .11    .80    .01    20    0.    500.   6569.      0.      1.    .000     000.
'Solar_PV'    0    2000  2006   .14    .80    .01    20    0.    393.   5887.      0.      1.    .000     000.
'Solar_PV'    0    2007  2009   .16    .80    .01    20    0.    344.   5251.      0.      1.    .000     000.
'Solar_PV'    0    2010  2014   .18    .80    .01    20    0.    306.   4625       0.      1.    .000     000.
'Solar_PV'    0    2015  2020   .20    .80    .01    20    0.    275.   4004.      0.      1.    .000     000.
'Fuel_Cell'   3    1993  1999   .40    .94     0.    20   .66    125.   5000.     15.     .95      0.       0.
'Fuel_Cell'   3    2000  2004   .40    .94     0.    20   .66    125.   5000.     15.     .95      0.       0.
'Fuel_Cell'   3    2005  2009   .40    .94     0.    20   .66    125.   3000.     15.     .95      0.       0.
'Fuel_Cell'   3    2010  2014   .40    .94     0.    20   .66    125.   2300.     15.     .95      0.       0.
'Fuel_Cell'   3    2015  2020   .40    .94     0.    20   .66    125.   1600.     15.     .95      0.       0.
'Micro_Tur'   3    1993  1999   .240   .94     0.    20   .66    125.   9700.     15.     .95      0.       0.
'Micro_Tur'   3    2000  2004   .240   .94     0.    20   .66    125.   9700.     15.     .95      0.       0.
'Micro_Tur'   3    2005  2009   .240   .94     0.    20   .66    125.   9700.     15.     .95      0.       0.
'Micro_Tur'   3    2010  2014   .240   .94     0.    20   .66    125.   9700.     15.     .95      0.       0.
'Micro_Tur'   3    2015  2020   .240   .94     0.    20   .66    125.   9700.     15.     .95      0.       0.
```

## Commercial Sector Distributed Generation

### Commercial Model Introduction

The NEMS Commercial Model has a primary level of disaggregation by nine Census divisions and eleven building types. The model considers energy consumption for three major fuels in a wide variety of end uses, within an accounting scheme that takes explicit account of new and replacement capital stock both in buildings and in energy-using equipment. The model also considers energy consumption for district heating and for minor fuels in a simpler fashion. The choice algorithms for the major fuels energy-using equipment are done using a least-cost simulation disaggregated over decision categories and discount rate categories. The simulation for new, replacement and retrofit equipment is based upon various annualized costs for competing equipment across general and specific categories of equipment.

Up to and through the Annual Energy Outlook (AEO) 1999, the NEMS commercial model has forecasted an amount of cogeneration using a growth model. This model began with a base level of cogeneration in 1996 and grew it over time based largely upon the growth in floorspace. The model did not consider economic issues dealing with technologies and their efficiencies and costs. However, in addition, some of the energy efficiency modeling might be considered to be a form of distributed generation. During 1999, in preparation for the AEO 2000 and other analyses, preliminary work has been done to substitute a new, technology-based distributed generation modeling routine to the commercial model. All the work is preliminary and is in a testing stage and has not yet been finalized at the time this report is being written. Most of the information that is provided here has been shared with us by the NEMS modelers, but may have changed by the time this is read.[25]

### Distributed Generation Modeling Background

The new, preliminary commercial sector distributed generation algorithm is very similar to that described already for the residential sector. It has the potential to evaluate seven technologies consisting of photovoltaics, fuel cells, conventional gas, conventional coal, conventional oil, conventional MSW, and micro turbines. The input file represents all seven of these technologies, but conventional coal is in essence turned off with high capital costs.

The penetration of each technology is modeled in two separate categories consisting of exogenous penetration and endogenous penetration. The exogenous penetration consists of a fixed exogenous amount that is in an input file and is subsequently read in and directly implemented. The endogenous penetration is the subject of the model algorithm and its calculation is dependant upon a variety of variables including prices, costs, consumptions, and various parameters.

The algorithm and most inputs for both exogenous and endogenous penetration are detailed by census division and run year by year starting in 1996. The exogenous penetration amounts are specified by the

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[25] This information is from communications with the NEMS buildings sectors modelers and from a Buildings Sector Working Group Meeting on June 24, 1999. As noted, the work described here is preliminary and may change as further work is done.

total numbers of buildings and building type shares. The endogenous penetration is calculated as a rate (a fraction) which is applied to the total number of buildings of each type (as opposed to the square feet of floorspace). Each technology is specified and used in the code over five "vintages" to represent its change over time. For example, the first vintage for photovoltaics covers the period 1993 through 1999 during which it is assumed that photovoltaics have an efficiency of 0.11 and a capital cost of $6569. The second vintage for photovotaics covers the period 2000 through 2006 during which it is assumed they have a better efficiency of 0.14 and a lower capital cost of $5887.

The endogenous penetration algorithm appears to operate year by year using three basic steps. In the first step, the model initializes a variety of variables such as the annual base Kwh output, and the annual base value of electricity saved. In the second step, the model does the financial calculations that determine the payback period for each technology, using a variety of price, cost, load, and economic data. In the third step the model determines the penetration rate for each of the technologies (based upon the payback period), applies it to the number of buildings, adds in exogenous penetration numbers and provides the results back to the model.

### Base Values and Initialization of Variables

Earlier versions of the commercial model had cogeneration. The initial amount of cogneration is available from an input file and this is put into the model. In each forecast year, for each Census division and each building type, and for each of the seven technologies, a variety of initial values are set up for later use. These include things such as:

- Price of the distributed generation. This is the price for electricity sold to the grid. For photovoltaics this is made equal to the airconditioning price[26] and for other technologies this is the airconditioning price with a net meter adjustment of 0.5.
- Overall capital cost in the base year. This is the equipment cost per kw plus the installation cost per kw times the base equipment output in kw.
- Maintenance cost in the base year. This is the maintenance cost per kw times the base equipment output in kw. It is assumed there is no maintenance cost for solar.
- Annual base kwh supplied by the base sized equipment. In the case of solar this takes into account the efficiency, the insolation (by region), the loss factor, the physical size of the array, and the base equipment output in kw. In the case of the other technologies this takes into account the operating hours, the availability, the loss factor, and the base equipment output in kw.
- Excess kwh. This measures how much more electricity is generated by the equipment than what is used in the average building. This is positive when there is an excess amount generated and sold to the grid, and this is negative otherwise.
- Value of electricity saved in the base year. This is the value of the electricity that is not otherwise purchased plus the value of any electricity that might be sold to the grid.
- Fuel input btu. This is the amount of the specific fuel type used to fuel the technology. This does not apply to solar.
- Waste heat btu. This is the amount of waste heat generated by the technology that could be

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[26] As explained earlier for the residential sector, the commercial model also uses separate prices for most of the commercial end uses. These are provided by the electricity model and are meant to represent the effect of time-of-day pricing.

applied to water heating. This does not apply to solar.

- Water heating consumption. This is the average amount of water heating per building (unit energy consumption) that could potentially be displaced by the technology's waste heat.
- Fuel cost in the base year. This is the net cost of the fuel that is used by the technology. This does not apply to solar.

### Financial Calculations

In each forecast year, for each Census division and building type, and for each of the seven technologies, financial calculations are made over the lifetime of the equipment in order to determine the payback period for that equipment. The model performs these calculations by simulating the year-to-year transactions that would occur over a 30-year period (this is beyond the equipment lifetime). The more significant transactions that are simulated include:

- Down payment and annual payment. The down payment is an assumed percent of the overall equipment capital cost. The annual payment is based upon the total loan, the term of the loan, and the interest rate for the loan.
- Principal, interest, loan balance. In each simulation year, these are based upon the previous year's loan balance and the interest rate.
- Tax credit and tax deduction. The tax credit is an assumed amount that applies in one year. In each simulation year the tax deduction is based upon an assumed tax rate and the amount of interest paid and the amount of equipment depreciation plus the tax credit.
- Fuel costs and maintenance costs. In each simulation year these are the base year amounts augmented by the amount of assumed inflation over the years.
- Annual electricity generation and annual value of electricity saved. In each simulation year these are the base year amounts degraded by the amount of assumed degradation over the years. The value of electricity saved is also augmented by the amount of assumed inflation over the years.
- Net cash flow and cumulative net cash flow. In each simulation year, the net cash flow is the value of electricity saved in each year, plus the amount of the tax deduction, minus the payments (outlays), minus the fuel cost, minus the maintenance cost. In each simulation year, the cumulative net cash flow is the sum of the net cash flows in the current and all previous years.

The objective of the financial calculations is to come up with a payback period for each technology. The cumulative net cash flow is investigated in each year in order to determine the payback period. The payback period is the number of years until the cumulative net cash flow becomes a positive amount (and stays positive).

### Technology Penetration

In each forecast year, for each Census division and building type, and for each of the seven technologies, an (endogenous) penetration rate is calculated and assumed to apply to all buildings. The technology penetration is calculated based upon the payback period, the forecast year, and assumed coefficients. There are two steps to its calculation.

The first step is to calculate a maximum possible penetration rate using the payback period and an assumed coefficient. This is given by the inverse of the payback period times the coefficient. The input coefficient is 0.3, so if the payback period were 5 years, then the maximum penetration rate would be 0.2 * 0.3 or

0.06.

The second step is to calculate the actual penetration rate using the maximum penetration rate, the payback period, the number of years since the technology was introduced in the model, and an assumed coefficient.

$$\text{PenRate} = \text{MaxPenRate} - 1 / ( ( 1 / \text{MaxPenRate} ) + \exp ( \text{Alpha} * ( \text{YearsAvail} - \text{Payback} ) ) ).$$

This endogenous penetration rate in each year is multiplied by the amount of each building floorspace times the average floorspace per building to calculate the number of buildings using each technology that is determined endogenously. The model also adds a number of buildings using each technology that is determined exogenously. (The input file contains the exogenous number of buildings and a matrix of building type shares.) The sum of the endogenous and the exogenous is the total number of buildings using each technology forecasted by the model.

## Integration with Commercial Model and other NEMS Modules

In each forecast year, for each Census division, and for each of the technologies, the number of building types using each technology is used to calculate various results that are used in the commercial model or in other NEMS modules.

- Cumulative units and cumulative electricity generation. The number of building types using each technology are summed over time to get the number of cumulative units. Corresponding to this the number of building types using each technology are multiplied times the annual generation of electricity for each technology to get the electricity generation. This is summed over time to get the cumulative electricity generation.
- Cumulative own electricity use. All electricity generated up to the average unit electricity consumption is for own use. Any generation above this amount is sold to the grid. This can be summed over time to get the cumulative own electricity use.
- Cumulative gas usage and cumulative water heating btus. The number of building types using each technology times the gas consumption of the technology summed over time is the cumulative gas usage. The number of building types using each technology times the water heating displaced by the technology summed over time is the cumulative water heating displaced.
- Annual capital investment costs. The number of building types using each technology times the capital cost for that technology is the annual capital investment cost.

## Additional Comments

As for the residential model, the algorithm is in a very preliminary stage. The comments provide here only relate to this version.

Table 8 for the residential sector (in the previous section) showed a sample set of financial calculations simulated over a 30-year period for photovolatic technology in the forecast year 2000 using typical values from the input files. The preliminary costs and efficiencies for the commercial sector are the same as for the residential with the difference being the average installation size, the average building consumption and the commercial price of electricity. But the conclusions from the table are the same so it is not repeated here. It is clear from the table that the cost of the photovoltaic technology so exceeds the resulting value of energy savings that there is never a period in which it is paid back.  In this case the payback period is 30 years or more, and the consequence is that there is only a very tiny penetration.

Table 9 for the residential sector (in the previous section) illustrated a sample set of resulting penetration rates for different forecast years and for different payback periods.  Obviously, the larger the payback period in the same forecast year, the smaller the maximum and actual penetration.  The further out the forecast year, the greater is the resulting penetration for the same payback period.

Table 12 shows some very preliminary key inputs for the commercial sector distributed generation technologies.

## Table 12. Key Technology Inputs to Commercial Distributed Generation (Preliminary)

(These are examples from a very preliminary distributed generation input file.)

```
Penetration Function Parameters
0.7   0.3

Annual Operating Hours
 Tech1   Tech2   Tech3   Tech4   Tech5   Tech6   Tech7
  8760.   8000.   6000.   6000.   6000.   6000.   6000.

Net Meter Adjusts by Census Div (technologies across)
 T1  T2  T3  T4  T5  T6  T7
 1.  .5  .5  .5  .5  .5  .5
 1.  .5  .5  .5  .5  .5  .5
 1.  .5  .5  .5  .5  .5  .5
 1.  .5  .5  .5  .5  .5  .5
 1.  .5  .5  .5  .5  .5  .5
 1.  .5  .5  .5  .5  .5  .5
 1.  .5  .5  .5  .5  .5  .5
 1.  .5  .5  .5  .5  .5  .5
 1.  .5  .5  .5  .5  .5  .5

Solar Insolation Values
136.    New England, Boston
137.    Middle Atlantic, New York
138.    East North Central, Detroit
172.    West North Central, Omaha
196.    South Atlantic,Miami
161.    East South Central, Birmingham
180.    West South Central, Dallas
235.    Mountain, Albuquerque
168.    Pacific, Great Falls

Residential Combined Federal and State Tax Rate, DownPayPct, Interest Rate, Loan Years, Inflation
   .40       .10   .07   20. .03

            Fuel  First  Last   Avg          Loss  Degred. Eqp.  Tax   Recv  Install   Equip.    Maint       Tax Credit
Type        Type   Year  Year    kW    Eff  Factor Factor  Life Life    Eff    Cost     Cost     Cost    Avail Percent Maximum

'Solar_PV'    0    1993  1999    30.   .11    .80   .01     20.   40.    0.     500.    6569.       0.      1.     .10   25000.
'Solar_PV'    0    2000  2006    30.   .14    .80   .01     20.   40.    0.     393.    5887.       0.      1.     .10   25000.
'Solar_PV'    0    2007  2009    30.   .16    .80   .01     20.   40.    0.     344.    5251.       0.      1.     .10   25000.
'Solar_PV'    0    2010  2014    30.   .18    .80   .01     20.   40.    0.     306.    4625        0.      1.     .10   25000.
'Solar_PV'    0    2015  2020    30.   .20    .80   .01     20.   40.    0.     275.    4004.       0.      1.     .10   25000.

'Fuel_Cell'   2    1993  1999   100.   .40    .94    0.     20.   40.   .66     125.    3000.      15.     .95      0.      0.
'Fuel_Cell'   2    2000  2003   100.   .40    .94    0.     20.   40.   .66     125.    3000.      15.     .95      0.      0.
'Fuel_Cell'   2    2004  2009   100.   .40    .94    0.     20.   40.   .66     125.    3000.      15.     .95      0.      0.
```

```
'Fuel_Cell'   2    2010  2014   100.   .40     .94    0.     20.   40.   .66     125.    2300.      15.     .95      0.      0.
'Fuel_Cell'   2    2015  2020   100.   .40     .94    0.     20.   40.   .66     125.    1600.      15.     .95      0.      0.

'Conv_Gas'    2    1993  1999   250.  .350     .94    0.     20.   40.   .66     125.    1475.      15.     .95      0.      0.
'Conv_Gas'    2    2000  2004   250.  .350     .94    0.     20.   40.   .66     125.    1475.      15.     .95      0.      0.
'Conv_Gas'    2    2005  2009   250.  .350     .94    0.     20.   40.   .66     125.    1475.      15.     .95      0.      0.
'Conv_Gas'    2    2010  2014   250.  .350     .94    0.     20.   40.   .66     125.    1475.      15.     .95      0.      0.
'Conv_Gas'    2    2015  2020   250.  .350     .94    0.     20.   40.   .66     125.    1475.      15.     .95      0.      0.

'Conv_Coal'   6    1993  1999   250.  .300     .94    0.     20.   40.   .66     999.    9999.      15.     .95      0.      0.
'Conv_Coal'   6    2000  2004   250.  .300     .94    0.     20.   40.   .66     999.    9999.      15.     .95      0.      0.
'Conv_Coal'   6    2005  2009   250.  .300     .94    0.     20.   40.   .66     999.    9999.      15.     .95      0.      0.
'Conv_Coal'   6    2010  2014   250.  .300     .94    0.     20.   40.   .66     999.    9999.      15.     .95      0.      0.
'Conv_Coal'   6    2015  2020   250.  .300     .94    0.     20.   40.   .66     999.    9999.      15.     .95      0.      0.

'Conv_Oil'    3    1993  1999   250.  .390     .94    0.     20.   40.   .66     125.     175.      15.     .95      0.      0.
'Conv_Oil'    3    2000  2004   250.  .390     .94    0.     20.   40.   .66     125.     175.      15.     .95      0.      0.
'Conv_Oil'    3    2005  2009   250.  .390     .94    0.     20.   40.   .66     125.     175.      15.     .95      0.      0.
'Conv_Oil'    3    2010  2014   250.  .390     .94    0.     20.   40.   .66     125.     175.      15.     .95      0.      0.
'Conv_Oil'    3    2015  2020   250.  .390     .94    0.     20.   40.   .66     125.     175.      15.     .95      0.      0.

'Conv_MSW'   10    1993  1999   250.  .240     .94    0.     20.   40.   .66     125.     900.      15.     .95      0.      0.
'Conv_MSW'   10    2000  2004   250.  .240     .94    0.     20.   40.   .66     125.     900.      15.     .95      0.      0.
'Conv_MSW'   10    2005  2009   250.  .240     .94    0.     20.   40.   .66     125.     900.      15.     .95      0.      0.
'Conv_MSW'   10    2010  2014   250.  .240     .94    0.     20.   40.   .66     125.     900.      15.     .95      0.      0.
'Conv_MSW'   10    2015  2020   250.  .240     .94    0.     20.   40.   .66     125.     900.      15.     .95      0.      0.

'Micro_Tur'   2    1993  1999    50.  .300     .94    0.     20.   40.   .66     125.     875.      15.     .95      0.      0.
'Micro_Tur'   2    2000  2004    50.  .300     .94    0.     20.   40.   .66     125.     875.      15.     .95      0.      0.
'Micro_Tur'   2    2005  2009    50.  .300     .94    0.     20.   40.   .66     125.     875.      15.     .95      0.      0.
'Micro_Tur'   2    2010  2014    50.  .300     .94    0.     20.   40.   .66     125.     875.      15.     .95      0.      0.
'Micro_Tur'   2    2015  2020    50.  .300     .94    0.     20.   40.   .66     125.     875.      15.     .95      0.      0.

Building Type Share Matrix for Non-Economic Penetrations
   T1   T2   T3   T4   T5   T6   T7
  .00  .00  .00  .00  .00  .00  .00    Assembly
  .10  .10  .10  .10  .10  .10  .10    Education
  .00  .00  .00  .00  .00  .00  .00    Food Sales
  .00  .00  .00  .00  .00  .00  .00    Food Service
  .00  .10  .10  .10  .10  .10  .10    Health Care
  .10  .05  .05  .05  .05  .05  .05    Lodging
  .50  .70  .70  .70  .70  .70  .70    Office-Large
  .20  .05  .05  .05  .05  .05  .05    Office-Small
  .10  .00  .00  .00  .00  .00  .00    Merc/Service
  .00  .00  .00  .00  .00  .00  .00    Warehouse
  .00  .00  .00  .00  .00  .00  .00    Other
```

## Industrial Sector Cogeneration

### Industrial Model Introduction

The NEMS Industrial Model has a primary level of disaggregation by four Census regions and 15 industry types. The model considers energy consumption for a wide variety of fuels (including byproduct fuels, and the conversion of fuels into steam), within an accounting scheme that takes into account of major energy processes and flows for several energy intensive industries. The model is not technology cost based so does not use explicit choice algorithms, but instead uses a series of conservation-cost type curves in key energy using industries to determine the efficiency of fuel usage in a number of processes and flows.

Up to and through the Annual Energy Outlook (AEO) 1999, the NEMS industrial model has forecasted an amount of cogeneration by relating it to the growth in steam and in byproduct fuels. This model began with a base level of cogeneration in 1996 (from EIA Form 867 data) and grew it over time based largely upon the growth in steam and on the growth in byproducts in the paper industry. The model considered three prime movers and renewables, but did not consider economic issues dealing with technologies and their efficiencies and costs. During 1999, in preparation for the AEO 2000 and other analyses, preliminary work has been done to substitute a new, technology-based distributed generation modeling routine to the industrial model. This will substitute only for the steam part of the previous cogeneration model. In the previous model, the cogeneration forecast was not based on a financial investment model and it was determined that a financial assessment really was a necessary feature of the industrial model for a variety of analyses that have been ongoing. All the work is preliminary and is in a testing stage and has not yet been finalized at the time this report is being written. Most of the information that is provided here has been shared with us by the NEMS modelers, but may have changed by the time this is read.[27]

### Cogeneration/Distributed Generation Modeling Background

There are two main pieces to the industrial sector cogeneration model. There is cogeneration based upon steam needs throughout industry, and there is cogeneration based upon the availability of byproducts in the paper industry. The steam-based cogeneration throughout industry is the piece that is being replaced for the AEO 2000. The model is detailed by a mix of nine Census divisions and four Census regions (the level of detail in the full industrial model) and the usual 15 industry types.

The model uses EIA-867 historical and planned capacity data to put together a database of actual capacity for 1995 through 1997. The capacity in 1997 is used as the base from which to forecast future capacity. The cogeneration algorithm operates year by year using two basic steps. In the first step, the model calculates the cogeneration at a fairly high level of detail. From the historical starting point for generation, the model uses the forecasts of byproducts and of technology costs and steam capacity to determine the growth in each category of cogeneration. This generation is split into that for own use and for sales. In the second step fuel consumption is determined, and variables are prepared for other parts of the industrial model and other NEMS modules.

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[27] Most of this information based on a presentation at an Industrial Sector Working Group Meeting on July 22, 1999. As noted, the work described here is preliminary and may change as further work is done.

## Generation in the Paper Industry using Byproducts

The industrial model forecasts byproduct fuels for the paper industry and these are gathered for use in determining generation. Generation is forecast in the years 1998 and beyond. In the paper industry the prime mover is a steam turbine, and it is assumed that byproduct fuels (biomass such as wood pulp and chips) will be used to the level of their availability. The amount of generation is equal to the amount of generation in the previous year plus the incremental generation from the incremental biomass available in the current year. This uses a fixed, assumed conversion factor/heat rate.

## Generation Based Upon Combined Heat and Power Technology Penetration

It is in this area that a new preliminary model is being added. Previously the industrial model considered three prime movers and renewables. The renewables are forecasted above in the paper industry. The new model considers only one area of growth; that is in natural gas combustion turbines (GCTs). This forecasting of cogeneration is applies to the area of the traditional cogeneration opportunities in the industrial sector but does not include the paper industry and does not include the refinery sector. It does not apply to the "non-traditional" cogeneration opportunities, that is merchant firms primarily in the power supply business.

The basic idea is that the GCTs are built to meet the facility steam requirements depending upon the economics. There are basically three steps to the model. First, assess the thermal base to be met by new cogeneration plants, second, size the cogeneration system for each load segment and evaluate the economics, and third, assess the market penetration based upon the payback period.

*Assess the Thermal Base*. The first thing that is done is to determine the amount of the total steam load that is forecasted for the industry in each region. Some of this steam is already being met by existing cogenerators, either from the historical database or from cogeneration that has been added in subsequent forecast years. The amount of steam that is available (not currently being used) is the basis for new cogenerators. An example of the steam that is available relative to the amount used for cogeneration in 1997 is shown in very round numbers in the following table. The steam that is available is forecasted in the industrial model in each year and will change over time.

The steam uses are then classified into size range segments based upon the boiler size distribution. The model uses four size range segments (10-50 mmbtu/hr, 50-100 mmbtu/hr, 100-250 mmbtu/hr, and greater than 250 mmbtu/hr) that are derived from a GRI/EEA study with data from 1993.

*Size the Cogeneration System and Evaluate the Economics*. In each industry the cogeneration systems are sized to meet the average steam load. There are five cogeneration system sizes, each with a different set of characteristics. A preliminary set of the systems and characteristics are shown in the following table.

**Table 13. Steam Availability Versus That Used for Cogeneration, 1997**
(Preliminary examples from an Industrial Sector Working Group Handout, July 22, 1999)

| | Total Steam Load (Trillion Btu) | Cogeneration Steam (Approximate TBtu) | Percent Cogeneration |
|---|---|---|---|
| **Food** | 538 | 120 | 22% |
| **Paper** | 1,613 | 1,170 | 73% |
| **Chemicals** | 1,090 | 510 | 47% |
| **Primary Metals** | 175 | 160 | 91% |
| **Other Manufacturing** | 1,123 | 140 | 12% |
| **Total** | 4,539 | 2,100 | 46% |

**Table 14. Characteristics of Candidate Cogeneration Systems**
(Preliminary examples from an Industrial Sector Working Group Handout, July 22, 1999)

| | Candidate Cogeneration Systems | | | | |
|---|---|---|---|---|---|
| | **1** | **2** | **3** | **4** | **5** |
| **Characteristics** | | | | | |
| **Electricity Capacity (kw)** | 1,000 | 2,500 | 5,000 | 10,000 | 40,000 |
| **Total Installed Cost (97$/kw)** | $1,600 | $1,400 | $1,200 | $1,000 | $950 |
| **Capacity Factor** | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 |
| **Overall Efficiency** | 0.70 | 0.70 | 0.70 | 0.75 | 0.80 |
| **Overall Heat Rate (btus/kwh)** | 14,217 | 13,132 | 11,263 | 10,515 | 9,749 |
| **Net Heat Rate (btus/kwh)** | 6,042 | 5,907 | 5,673 | 4,922 | 4,265 |
| **Steam Output (mmbtu/hr)** | 6.5 | 14.5 | 22.4 | 44.7 | 175.5 |
| **Power Steam Ratio** | 0.52 | 0.59 | 0.76 | 0.76 | 0.78 |

At this point the electric capacity is determined from the power-steam ratio and the steam capacity. An economic evaluation is then performed for the cogeneration investment, based on the appropriate technology characteristics, the cost of natural gas, and the value of avoided electricity purchases. A sample cogeneration system financial evaluation is shown in the following table.

**Table 15. Sample Cogeneration System Evaluation**
(Preliminary examples from an Industrial Sector Working Group Handout, July 22, 1999)

| | |
|---|---|
| *Prices ($/mmbtu)* | |
| Electricity | 16.61 |
| Natural Gas | 4.03 |
| *Cogeneration System Assumptions* | |
| Cogeneration Capacity (kw) | 10,000.00 |
| Cogeneration Electricity Output (mwh) | 70,080.00 |
| Power-to-Steam Ratio (Btu-Elec/Btu-Heat) | 0.76 |
| Steam Output (mmbtu/hr) | 44.74 |
| Heat Rate (btu/kwh) | 10,515.00 |
| Fuel Use (bill btu/year) | 736.89 |
| Overall Efficiency | 0.75 |
| *Existing System (or conventional system)* | |
| Steam Output (mmbtu/hr) | 44.74 |
| Boiler Efficiency | 0.80 |
| Fuel Use (bill btu/year) | 391.94 |
| *Electricity Value* | |
| Electricity Price ($/mwh) | 56.69 |
| Electricity Value (Th.$/year) | 3,972.81 |
| *Operating Cost (thousand $/year)* | |
| Cogeneration System | 2,970.69 |
| Existing System | 1,580.07 |
| Incremental Fuel Cost | 1,390.61 |
| *Incremental Investment for Cogeneration (Th. $)* | 10,000.00 |
| Gross Profit (Electricity Savings - Fuel Cost) | 2,582.20 |
| Payback Period | 3.87 |
| Economic Fraction | 0.23 |

*Assess the Market Penetration Based On the Payback Period.* The payback period was calculated in the previous step, and this is used to determine the actual market penetration. A relationship is assumed between the payback period and the willingness of firms to invest. This curve then defines the "economic" fraction of firm that will invest in each cogeneration option. The total amount of steam that is available beyond that already used for cogeneration defines the technical potential for new cogeneration, and this is multiplied by the economic fraction to obtain the economic potential for new cogeneration. Annual additions to cogeneration are based on the economic potential at a 5 percent annual penetration rate.

## Fuel Consumption and Integration

The amount of fuels consumed (biomass and natural gas) is calculated in each of the two models and is accounted for in the industrial model. Historical data on sales versus own use at a high level of detail is subsequently used in the forecast years to factor the amount of sales versus own use. Information is passed to the industrial model and other NEMS modules.

## Electricity Sector Distributed Generation

### Electricity Model Introduction

The NEMS Electricity Model is disaggregated by 13 NERC regions and represents central station generating units along with non-utility generating units, renewables, and non-traditional cogeneration. The model represents the conversion of fuels and other energy sources into electricity and the transmission and distribution of that electricity, taking into account capacity planning, dispatch, and pricing. The model is extensively technology cost based and relies upon a wide variety of financial assumptions and calculations. The model is organized into a series of modules that model various aspects such as electricity time-of-day load shapes, capacity planning for utilities and non-utilities, dispatch of available utility and non-utility units, and financial accounting and pricing.

Up to and through the Annual Energy Outlook (AEO) 1999, the NEMS electricity model has forecasted an amount of "non-traditional" cogeneration which was meant to represent the cogeneration of electricity by merchant firms primarily in the power supply business. (Modeling of "traditional" cogeneration was left to the end use models.) The base level of historical non-traditional cogeneration was from EIA Form 867 data. During 1999, in preparation for the AEO 2000 and other analyses, preliminary work has been done to add a new distributed generation modeling routine to the electricity model. All the work is preliminary and is in a data gathering and testing stage and is still somewhat sketchy at the time this report is being written. Most of the information that is provided here has been shared with us by the NEMS modelers, but may have changed by the time this is read.[28]

### Distributed Generation Background

The major driving force leading to distributed generation in the future will be the unbundling of transmission and distribution costs and the subsequent recognition that distributed generation resources can substitute for transmission and distribution resources. This was discussed at length earlier in this report. On average, the distributed generation technologies would have a hard time competing. However, it has been shown that there is a wide variance in small area/planning area marginal distribution costs for various utilities (see the discussion and table under *Spatial Load Issues*, above). When the distribution of costs is taken into account, it is clear that there are a number of opportunities for distributed generation resources to substitute for and defer investments in the high-cost transmission and distribution resources. The electricity model attempts to address this particular factor in its new proposed modeling for distributed generation.

### The Proposed Distributed Generation Model

The existing capacity planning algorithm in the electricity market module (EMM) is not appropriate for the modeling of distributed generation technologies. This is because the EMM competes all available generating technologies against one another assuming they will impose the same transmission and distribution costs on the system (although wind is an exception). There is no explicit representation of the dispersion in transmission and distribution costs that occurs within a typical utility system. The distributed

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[28] Most of this information is based on communications with NEMS electricity modelers. As noted, the work described here is preliminary and sketchy and may change as further work is done.

generation technologies and costs for transmission and distribution could probably be added to the model at a regional level so that it could be solved for a least-cost solution. However, because there is a wide array of distributed generation technologies and it would require a number of steps to adequately represent the dispersion in T&D costs, it would greatly expand the size of the model and make its operation unwieldy. The alternative would be to develop a distributed technology submodule which, using information about the costs and performance of distributed technologies, the avoidable transmission and distribution costs, avoidable losses, and regional sales, would screen the available technology options. The result would be to prepare regional distributed generation technology supply steps that would then be passed to the EMM and be competed against the other technology options.

A number of inputs would be needed by a module of this type. Information about some of these inputs is better known than others, but in some cases much of the data would have to be based upon informed judgement. Some of the categories of inputs that would be needed include:

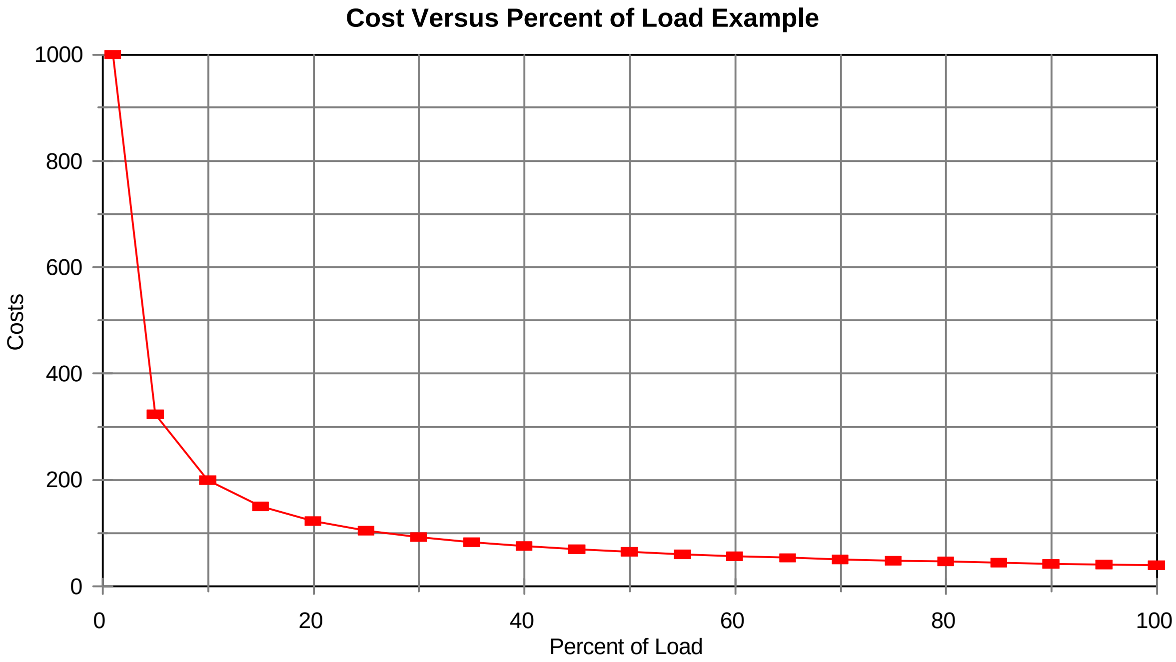
*Distributed Generation Technology Cost and Performance Characteristics*. This is simply information about each of the distributed generation technologies and is fairly available or can be adequately estimated. These include the first year available, typical size (megawatts), construction lead time (years), overnight costs-first (current), overnight costs-nth (mature), variable O&M (mills per Kwh), fixed O&M ($/Kw), heat rate (btu/Kwh), fuel cost class (sector's prices that this technology would use), NOx emission rate (lbs./mmbtu), SO2 emission rate (lbs./mmbtu), load cycle (base, int., peaking), fuels usable (coal, distillate oil, residual oil, etc.).

*Regional Distribution of Avoidable T&D Costs*. This is perhaps the most difficult information to develop and will be the most controversial. The basic idea here is to develop regional curves using information from some recent studies on the "marginal distribution capacity costs" (MDCC). (This was defined and discussed earlier in this report.) It will be difficult to summarize and regionalize this distribution of costs, so a variety of assumptions will have to be made. Since this distribution will be the major driving force for the distributed generation forecast, it will have to be defined and constructed very clearly. For each region there would be several marginal T&D cost "classes" and each cost class in each region would serve a percentage of load or megawatts of load in that region.

In the end the relationship might look something like in the following figure. In the figure, for example, it can be seen that 10 percent of the load is served by areas that have a marginal distribution capacity cost that is greater than 200 dollars per kw. If there is a distributed generation technology with a cost less than or equal to $200, then it might be cost effective to use that DG technology rather than to expand the T&D network.

*Regional Percent of Losses and T&D Costs Avoidable*. In each region there would be a percent of losses avoidable which represent the reduction in losses when a distributed resource is installed instead of central station facility. In each region there would be a percent of T&D marginal costs avoidable which represent the portion of the transmission and distribution costs avoidable when a distributed resource is installed (some of the T&D costs are for maintenance and upgrades and are not avoidable).

*Market Penetration Parameters*. The penetration of distributed resources might evolve slowly even when the economics are strongly in their favor. This is true because the technologies are new and somewhat untested, but even more important, the market based pricing signals (locational marginal cost pricing for generation and distribution services) needed to make these technologies attractive are only now evolving.



There may also be some siting problems in some areas that limit their penetration. For these reasons, the model will incorporate a market penetration function that will partially constrain the entrance of these distributed generation technologies into the market.

*Inputs/Outputs from NEMS/EMM*. Information needs to be passed back and forth between this model and the other models of NEMS and EMM. The inputs include cost of capital, fuel costs / foresight, regional sales in the current year, regional sales in the previous year, etc. The outputs include the multiple supply steps that include the size, capital cost, variable O&M, fixed O&M, lead time, and fuel cost class.

# Proposed Supplementary Modeling of Distributed Generation

## Introduction to the Modeling

Cogeneration and other self-generation projections are calculated several places in the NEMS models. The distinction has been made between "traditional" cogeneration and "non-traditional" cogeneration. All of the traditional cogeneration (and other generation) has been modeled in the commercial and industrial demand models. The presumption is that this is generation by the end use customer that is intended as part of the business in that sector and is not meant as a separate business. In this case most of the generation is typically used in the sector with only small amounts being sold to the grid. All of the non-traditional cogeneration has been modeled in the electricity model. The presumption is that this is cogeneration by merchant firms that are primarily in the power supply business and that all of this generation is sold to the grid.

For the modeling of distributed generation, this distinction is probably a good first cut. This is close to the modeling framework which was described earlier that considered end use customers separately from the other actors (generators, distributors, third-parties). The motivations and incentives in the end use sectors are different from those of the other actors. However, in the future there may be considerably more generation from the end use sectors that is sold to the grid.

The basic preliminary approach currently being used by NEMS modelers to represent distributed generation in each of the sectors was previously described in some detail.[29] In most cases the work is only at a testing stage, but the basic approach seems appropriate for each respective sector. At the time this task was originally proposed, there was no clear knowledge that the NEMS modelers would be creating distinct, sectoral distributed generation routines. Since we would have been using the same basic approach, there is no benefit to duplicating the same work. At this point the most useful approach would be to work in parallel or to supplement the work that is already being done. The NEMS work is very preliminary and is still evolving, so our comments and suggestions for enhancements are made within that context. For example, some comments have already been made at NEMS working group meetings and may already be under consideration. In any event, within the context of this task and with the idea that we could add additional value and resources to what is already being done, we can note some open issues in each sector and suggest ways they might be addressed. Some of the comments listed below are general and apply to all of the sectors and some are very specific to each sector. First we provide several comments that apply generally to the sectors and to the evolving distributed generation modeling, and then we discuss the work that we can do to supplement the modeling.

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[29] The emphasis in these models is on distributed *generation* of electricity. Although, in this paper, we have been working with a broader definition that also includes storage technologies and demand side management, for the modeling we will also concentrate on the technologies for generation. Storage technologies might also be treated in a similar fashion, depending on the context. Demand side management is, to some degree, already considered in each of the demand models, through the model elasticities and trends for equipment efficiencies, conservation measures, and occupant/management behavior.

## Potential Areas for Further Work

### Cross-Cutting Considerations

There are some issues that must be dealt with in most or all of the sectors.

*Electricity Pricing*. There are at least two aspects to this, the price at which electricity is purchased by end use customers, and the price at which they can sell electricity back to the grid. The overall deciding factor for distributed generation in each sector is whether the cost to generate electricity (minus any revenue generated by selling the electricity) is less than the cost to purchase electricity. On average, in the end use sectors and in the absence of cogneration or byproducts, it does not generally appear that this would be the case. However, for various reasons not all end use customers face the average price for electricity and might pay higher prices. The key to the modeling of distributed generation is to capture the customers at the edge of the distribution that face the higher electricity prices.

There will be a greater variance in prices as we move into the future in a world with electricity restructuring and time-of-day electricity prices. This is also especially true if there is unbundling of electricity sector transmission and distribution costs and those costs are passed through to end use customers. The distributed generation routines in the end use models need to look at the higher end prices to find any market penetration. The preliminary versions in the buildings sectors is tending in that direction by using air-conditioning prices (the NEMS models use end-use pricing to simulate time-of-day pricing). It may be that some of the distributed generation technologies become more cost effective if used to produce own electricity during the peak price periods and used to sell electricity to the grid during non peak price periods. Some additional information on time-of-day price variance is available from the electricity model.

The prices that are paid for sales to the grid are not necessarily the end use price and the buildings models reflect this by using a net metering factor for different technologies. For all end use sectors, when net metering is not assumed, the price of electricity sold to the grid should be equal to the generation price, rather than the delivered price. Although they are not currently being used, these prices should be available from the electricity model.

*Technology Competition*. The end use models seem to forecast the penetration of each of the technologies independently of the other technologies. The various technologies should be competing against each other. Using something like a nested logit, it would be valuable to compete the various technologies against each other to determine a slate of potential technologies. (It would be best to use a modeling technique which results in a slate of several technologies rather than have a single technology win all the market share.) Subsequently, the cost characteristics for this slate of technologies (probably a prototype for all of them) would be compared to the cost of electricity to come up with the overall penetration rate for the whole slate. (There may some question as to how to get the prototype costs and whether it will compete at the right level in this "nested" type of procedure.)

*Third Parties*. A third party entering the market might change the scale of the projects or the financing characteristics of the investments.

*Financial Analysis and Penetration Function*. There may be alternatives to the particular algorithms that are used for the financial analysis and for the penetration function. However, those that are currently being used in the preliminary version provide the appropriate flows and effects, and it would be difficult to conclude that there is something that is better or more appropriate.

*Non-Economic Factors*. It would be useful to have a mechanism to be able to add non-economic factors into the financial analysis, most likely by adding or subtracting a premium to the pricing. An example might be green pricing that creates a niche market that could be represented in effect by creating a price premium.

### Residential Sector

The modeling approach in the residential sector looks at the various technical and economic characteristics of a variety of distributed generation technologies and does a financial analysis to compare their costs versus the cost for purchased electricity. The results of the financial analysis are used to determine the market penetration of the technologies. An additional amount of penetration that is likely due to niche markets and is not cost based is determined exogenously. At this point it appears that the result will be only a very small penetration of distributed generation into the residential sector.

*Technology Sizing*. The size or scale of the distributed generation technologies might make a difference to the outcome of the financial analysis. It may be important to allow the model to choose an optimal technology sizing for each circumstance.

*Technologies Slate*. There may be some technologies that should be added to the slate of technologies in the residential model, such as conventional (reciprocating engines) gas and oil generators.

*Existing Housing Units*. The endogenously calculated technology penetration rate is applied in each year to new housing units only. There is probably some penetration that might be expected in existing housing units. These may face a different cost of capital since it is less likely that the distributed generation costs would be financed as part of a home loan. It appears from discussions with NEMS modelers that they are already working on adding structure to evaluate these technologies in existing housing units.

*Multi-Family Housing Units*. All penetration of distributed generation technologies is applied to single-family housing units. There may be some segment of multi-family housing, specifically large buildings and/or clusters of buildings, in which investments are made on a larger scale to be shared by all the units in the buildings. This would be more like the activity in the commercial sector. The scale of the technologies would be much larger, and capital might be more available and at a lower cost. This might also apply to other types of housing units if there is some kind of "community" activity.

### Commercial Sector

The modeling approach in the commercial sector is basically the same as that in the residential sector, with an economic analysis as well as an exogenous penetration. At this point it appears that the result will be only a very small penetration of distributed generation into the commercial sector.

*Technology Sizing*. The size or scale of the distributed generation technologies might make a difference to the outcome of the financial analysis as in the residential sector. It may be important to allow the model to choose an optimal technology sizing for each circumstance.

*District Services*. One segment of the market for cogeneration in the commercial sector is that of district services. The modeling of district services in the commercial sector is based upon a historical starting point and a growth based on floorspace growth. There is no interaction between the district services segment and other parts of the commercial model. Moreover, there is no connection between the modeling of district services and the modeling of cogeneration. It might be appropriate to rethink the modeling of district services, and how it relates to cogeneration. However, although there is some anecdotal evidence of growth in district services, most seem to think there is not much here.

*Building Types*. Perhaps certain building types are more likely to use distributed generation, such as hospitals, educational institutions, and government buildings (which are not a separate category in the commercial model).

## Industrial Sector

The modeling approach in the industrial model looks at the various technical and economic characteristics of natural gas combustion turbines and does a financial analysis to compare the costs versus the cost for purchased electricity. The results of the financial analysis are used to determine the market penetration of the technology. An additional amount of distributed generation is due to the use of byproducts in the paper industry.

*Technologies Slate*. There may be some technologies that should be added to the slate of technologies in the industrial model. The industrial model only considers natural gas combustion turbines for distributed generation (outside of the paper industry). The model could model additional technologies, for example reciprocating engines and black liquor gasification in the paper industry.

*Sales to the Grid*. There may be some significant markets that involve sales to the grid. Currently the fraction of sales to the grid is being imposed based on historical sales rather than on economic value.

*Oil Sectors*. The refinery sector in NEMS is separate from the industrial sector, but energy consumed in the refinery sector is accounted for in the industrial sector. Cogeneration is modeled in the refinery sector and in oil and gas production sectors and is passed to the industrial model. Is this as integrated as it should be?

## Electricity Sector

The modeling approach in the electricity model appears to key on the primary factor for distributed generation which is to look at the T&D cost distributions. Investments in distributed generation are made where there are high costs (basically instead of or to defer investments in T&D). This is a general, probabilistic approach, not tying into the specific geographical locations where the distributed generation is being invested. The various technologies are first competed against each other to develop a prototype technology that is then modeled versus the T&D cost distributions.

*Base Cost Distributions*. It is difficult to put together the cost distributions. There have been very few studies of the marginal distribution capacity costs (MDCCs) for utilities. Information on MDCCs will have to be extrapolated to NERC regions for the electricity model. Moreover, it is difficult to determine how to represent a fairly specific, local planning area cost distribution over a large region.

*Dynamics of Cost Distributions*. The cost distributions are dynamic and should change over time. There will have to be some way to model this dynamic behavior. Moreover, they should change in response to the penetration of distributed generation technologies. When a distributed generation investment is made in one local planning area, this should have an impact upon the MDCC in a number of other planning areas (due to the shifting of loads). How this impact should play itself out is an open question. Are the high-cost T&D planning areas clustered so that the one investment shaves off the high cost part of the cost curve? Or are they just randomly distributed so that the one investment flattens out the whole curve? Time-of-day loads would also have an impact and be affected by investments.

*Technology Competition*. The distributed generation technologies are competed against each other first. Will this competition select a single lowest cost technology? It would be appropriate for the competition to select a slate or distribution of technologies. The slate of technologies would be used to create a prototype with the average characteristics of the slate. This prototype would then be used to determine a potential penetration against the cost curve. Is using the average characteristics in the form of a prototype the appropriate technique in this case?

*Other Markets*. The driving force for the distributed generation routine is the high cost end of the spatial MDCC distribution. There may also be some other smaller markets with other motivations. One such market is that which is driven by power quality and reliability.

## Proposed Modeling Activities

As noted above, the most useful approach for modeling would be to work in parallel to supplement the work that is already ongoing in NEMS. We have noted a variety of issues above that might be worthy of some additional thought and work. Those that might be most tractable and of the greatest benefit are listed below. Each of these will be studied and implemented based upon the further information that is found. We expect that we can interact with and provide resources to the NEMS modelers for our joint benefit. Since the electricity sector work is the most preliminary and since we have not yet seen many of the actual details, we propose to continue to follow what is being done and to study aspects of the sector on our own.

Many of these proposals depend upon finding the ends of distributions or segmenting the market in various ways. In most cases, it would be useful if there were some way to split the market into “high-potential” and “low-potential” customers and perform the modeling on high-potential customers. This will be one of our key motives.

*Overlaps and Double Counting*. An important thing to note is that there are several independent models for distributed generation in the NEMS. We will look at all of these and at what each represents in order to investigate if there is any overlap or double counting. We will catalog in one place all of the distributed generation activities in the residential, commercial, industrial, refinery, oil & gas production, and electricity sectors and consider how they fit together. We have a considerable amount of expertise in activities that overlap across sectors.

*Electricity Pricing*. We propose to look at the price signals in each of the end use sectors as described above and determine what is the appropriate price to be used. Our expertise with the electricity model and electricity pricing should be a benefit. We will connect the correct prices to various parts of the models, and we can add options for a variety of policies. We will investigate whether the market can be segmented in some way so that technology choices and penetration can be made using prices at the end of the distribution rather than being based on an average price.

*Technology Competition*. The emphasis in this area will be on competing the slate of technologies against each other as described above. In most cases, this will involve adding a new mechanism to the technology choice and penetration algorithms.

*Third Parties*. We will add options to the financial calculations for changing the scale and financial characteristics of third-party investments. This would most likely be as a subsegment of the market.

*Non-Economic Factors*. We will catalog the various non-economic factors that might be considered and add mechanisms to the modeling that will allow these as options.

*Residential Sector*. We will investigate the issues mentioned earlier. This includes adding to the slate of technologies, looking into the sizing or scaling of technologies, considering a competition for multi-family housing units, and adding existing housing units (if they have not already been added).

*Commercial Sector*. We will investigate the issues mentioned earlier. This includes looking into the sizing or scaling of technologies, investigating the district services market with respect to related to distributed generation, and investigating whether certain building types should be related to distributed generation.

*Industrial Sector*. We will investigate the issues mentioned earlier. This includes looking into whether adding additional technologies would be beneficial, and more economic treatment of electricity sales to the grid.

As noted earlier, the current NEMS modeling of distributed generation is very preliminary. However, in the buildings sectors we have put the new routines along with their input files into our standalone versions of the AEO99 building models and have been running them on the PC. As the code becomes available, we can do the same with out standalone version of the AEO99 industrial model. Using the standalone models we are easily able to edit and test all the various alternatives and additions. Our process will involve the following steps.

*Model Output Reports*. We will create some output reports that provide a clear picture of the operation and results of the financial calculations, of the penetration function and technology choice, and of the resulting electricity generation and energy demand.

*Investigations and Code Changes*. We will study the variety of issues cited above, implement them into the model code for each sector, and test them for relevance and significance.

*Scenario Testing*. Once the models are fairly stabilized we will run a variety of scenarios that will reveal the various sensitivities and impacts of the distributed generation model.

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# Appendix I.  Summaries of Distributed Generation Related Reports and Articles

This outlines several reports having to do with distributed generation.  The emphasis in this outline typically deals with issues that might be of interest in a modeling effort.

## Transmission and Distribution System Cost Data Development:  Implementation Report

(Prepared for Energy Information Administraton, November, 1996, by OnLocation, Inc.)

### *Abstract*

The focus of this report is to identify the data requirements, assess the data availability, and review data sources for an enhanced characterization of transmission and distribution (T&D) costs in the NEMS electricity module.  The better characterization of costs associated with T&D is required to more completely assess the potential for selected distributed generation technologies.

### *Approach and Results*

Ideally a utility will produce distribution (and transmission) expansion plans based on a spatial distribution of forecast load growth for small areas.  Costs can vary significantly across these small areas.  One study cites a measure termed the marginal distribution capacity costs (MDCC, defined as the change in present value brought about by a 1 kw reduction in local area demand), that varies within one utility from 0 to 1641 dollars.  The report notes that there generally is a significant amount of demand that is at the high end of the scale and would be candidates for distributed resources.  The spatial analysis performed by some utilities is too detailed for a NEMS type model, but there are a series of steps that might be taken.

1.  A series of distributions of incremental costs (MDCC) could be estimated for a variety of utilities and in turn used to create a wide range of derived demand functions.  (The report provides more detail on how these are mathematically derived.)

2.  Using these distributions, assign to each NEMS electricity area a profile of incremental distribution costs using a subjective judgement for combining them over various types and densities of utilities in each area.

3.  Calculate the incremental growth in demand and the contribution to peak demand for each customer class in each region in NEMS.

4.  Output the incremental costs of generation and transmission in each NEMS region to establish a value that would be offset by the implementation of DG.

5.  Using the generalized analytic equations of derived DG demand we can arrive at a rough estimate of the derived demand for DG.

6.  Based on alternative estimates of various costs and availability of DG technology, estimate the

‘economical’ DG supply.

*Conclusions*

Before attempting to reconfigure the NEMS model to accommodate the issues surrounding DG technology, two key data developments should be undertaken. First, which should be readily accomplished, is development of a reliable cost and performance data base describing the DG technology at the scale, duty cycle, and location currently envisioned. Second, which is more difficult, is the development of a better data base to look at the spectrum of MDCC costs and the factors behind those costs. This would involve studying between 5 to 10 diverse utilities and considering how these change over time.

### Spatial Electric Load Forecasting

(Book written by H. Lee Willis of ABB Systems Control Division, Cary, NC and published by Marcel Dekker, Inc. in 1996)

*Abstract*

This is a comprehensive textbook about considerations and techniques for forecasting electricity loads for a utility on a spatial basis for transmission and distribution planning. A couple of chapters are also devoted to forecasting on a temporal basis.

Chapter 1 presents the requirements for the spatial forecast, including its spatial and temporal resolution, accuracy, compatibility with short- and long-range planning needs, and ability to assess uncertainty through multi-scenario analysis.

Chapter 2 looks at the temporal behavior of electric load -- how it varies as a function of time of day and season of year. T&D capacity needs are usually defined by the maximum (peak) demand. An important element of load modeling is coincidence -- the way in which local peak loads sum to area and regional peak loads. This chapter looks at ways of representing electric load and coincidence, and explains how to avoid several common errors in load curve analysis.

In Chapter 3, ways to model electric demand on a customer-class basis are investigated, including end-use models, building simulators, and weather normalization methods. The chapter concludes with a detailed look at a typical computer program for customer-class based, end-use load curve analysis.

### What’s in the Cards for Distributed Resources?

(Article written by Johannes Pfeifenberger, Philip Hanser, and Paul Ammann, in The Energy Journal, special issue on Distributed Resources in 1997)

*Abstract*

The electric utility industry is in the midst of enormous changes in its market structure. While the generation sector moves towards a truly competitive market, the utilities’ transmission and distribution functions are undergoing a transition to unbundled services and prices. These changes will affect the competition between distributed and central-station generation technology. Although the ultimate market potential for distributed generation may be significant, the market will be fragmented and heterogeneous. Distributed generation will likely succeed in some small and only a few medium-sized market segments, each narrowly defined by the segment's unique operation requirements. The largest potential market segment is for distributed generation technology with operational and economical characteristics suitable for peak shaving. Unbundling of utility costs and prices will make base-load and intermediate-load equipment, such as fuel cells, significantly less attractive in the largest market segments unless capital costs fall substantially below $1,000 per kilowatt.

A section on the comparative economics of distributed and central station generation provides an interesting table showing the unbundled costs of various technologies for central station generation versus those for distributed generation. At these costs, central station generation creates a significant hurdle for distributed generation technologies to overcome in the base-load and intermediate-load market segments. Despite the advantages of central station generation, there should be little doubt that distributed resources will be able to penetrate some market segments. Distributed resources are attractive primarily for four reasons. First, electric power from on-site generation may be cost effective if thermal energy can be used and is valuable. Second, the inefficient pricing at average utility rates provide some customers with savings if they install distributed resources (for example, those customers with low load factors). Third, with unbundling of prices, as utilities become more aware of high-cost customers and locations, they will find distributed resources increasingly attractive even if power delivered from central stations is less expensive on average. Fourth, perhaps the most significant potential for distributed resources exists in applications with substantial transmission and distribution cost savings (this is actually a special case of the unbundling in 3 above but is important enough to list separately). Note that much of the market for distributed resources based upon T&D savings will be created for peak-load or peak-shaving applications. Also note that although vertically-integrated utilities and distribution companies will have an incentive to install peak-shaving and load management equipment to increase the utilization of their T&D assets, customers and third parties will be provided with similar incentives only after rates are unbundled to reflect the underlying cost structure.

## Characterization of Distributed Resource Technologies

(Prepared by The Cadmus Group, SAIC, and OnLocation, July 1997.)

*Abstract*

This paper, the first in a series of three papers on distributed resource (DR) technologies, characterizes the various types of distributed resource technologies available, and evaluates them with respect to: (1) their impact on net air emissions (i.e., SO2, NOx, and CO2); (2) zoning and siting issues; (3) current and projected economic measures; (4) commercialization status; and (5) engineering considerations (e.g., intermittency, dispatchability, load following, and startup).

*Background*

Distributed resource technologies include small renewable and non-renewable generation units and demand side management measures that are sited in or close to a load center or at a customer's site. In the restructuring and deregulation environment these are of particular interest in order to control incremental generation cost in two ways:  (1) cost of incremental capacity is spread over the largest possible load; (2) cost of extending and upgrading the capacity of the T&d network to support new loads is minimized.  DR technologies can be added, close to the user site, in small capacity increments.  DR technologies can also benefit the environment either as renewables having no emissions or as DSM technologies causing lesser use of conventional fuels.

The vertically integrated electric utility structure has led to an electricity supply model in which central power station generation and the associated T&D system were sized to meet system-wide demand, rather than local peak demand.  The result is high capacity utilization of generation assets and lower capacity utilization of distribution assets.  DR technologies can be used to:  (1) extend existing T&D capacity and delay investment; and (2) delay addition of central station capacity.

*Description of Technologies*

The list of technologies in the paper reflect those with current or future potential for market penetration and resulting net impacts on primary air emissions.  Each technology is discussed and described in some detail.  The list of technologies includes:

> *Renewable Technologies*.  This includes landfill gas, animal waste, biomass generation systems (e.g., gasifiers and mass burn), municipal solid waste, photovoltaic systems (including hybrid systems such as photovoltaic/diesel), wind turbine systems (including hybrid wind/diesel systems), and solar thermal systems (e.g., parabolic trough and dish Stirling).
>
> *Non-Renewable Technologies*.  This includes mini-turbines and engines (20 kW or lower to 50 MW size range), combustion turbines, steam turbines, reciprocating engines, fuel cells, and coalbed methane.
>
> *Energy Storage Systems*.  This includes batteries, thermal energy storage, flywheels, superconducting magnetic energy storage (SMES), supercapacitors, and hydrogen.
>
> *Demand-Side Management Technologies*.  This includes high efficiency heating, cooling, ventilation, and water heating technology, active solar heating and cooling technology, high efficiency lighting and ballasts, energy efficient motors and motor systems, energy efficient refrigeration, building envelope technologies (e.g., advanced glazing, insulation, and passive solar design strategies), and load control devices.

*Technology Evaluation*

The technologies cited above are evaluated according to five factors consisting of impact on net air emissions, zoning and siting issues, current and projected economic measures, commercialization status, and engineering considerations including intermittency, dispatchability, load following, and start-up.

### Factors Affecting Market Penetration of Distributed Resource Technologies

(Prepared by The Cadmus Group, SAIC, and OnLocation, July 1997.)

*Abstract*

This paper, the second in a series of three papers on distributed resource (DR) technologies, characterizes the factors limiting the market penetration of distributed resource technologies.

*Background*

In 1996 FERC issued two rulings that will shape the way electricity is sold in the future. Order No. 888 effectively provided open access to the transmission system and Order No. 889 requires a system to provide tariff and available transmission capacity data along with the separation of utility power marketing and transmission system operation functions. The industry of vertically integrated utilities is evolving into separate generation companies and transmission entities (such as POOLCOs) along with the introduction of power marketers and energy service providers. DR resources allow these new industries to cut costs by adding very energy efficient incremental capacity as loads grow and allows customers to reduce demand thereby effectively extending utility generation capacity.

*Description of Near- to Medium-Term (1997-2007) Factors to be Considered*

A variety of factors dealing with the market penetration of DR technologies are discussed. These include:

Emergence of Retail Wheeling
Disaggregation of the Vertically Integrated Electric Utility Structure
Merging of Electric and Gas Concerns
Newly Emerging Roles for Power Marketers, Energy Service Providers, and Others
Consumer Perceptions, Attitudes, and Values
Evolving Environmental and Siting Constraints
Changing Planning Models and Their Valuation of Distributed Resources
Form Of, and Incentives Created By, Existing and Prospective Regulation of T&D Functions

*Market Penetration Evaluation of Technologies*

This section provides a series of tables that evaluates the potential market penetration of each DR technology based upon the factors discussed above and upon other considerations. These are organized into:

*Identification and Assessment of Existing Barriers*. This section includes such things as: (1) high capital cost and long paybacks; (2) concerns about the impact of a high penetration on electricity dispatchability, grid reliability, and power quality; (3) concerns about performance and reliability of DR technologies; (4) miscellaneous concerns about sticking with familiar technologies and building and electric codes.

*Effect of Restructuring and Deregulation*. This section is concerned with the positive impact that restructuring and deregulation will have on the market penetration of DR technologies, discussing the factors listed above.

*New Barriers Due to Restructuring and Deregulation*. This section is concerned with the potential that restructuring and deregulation may also raise some new barriers, or not remove some of the old barriers.

### Proposals for Addressing Barriers to Market Penetration of Distributed Resource Technologies

(Prepared by The Cadmus Group, SAIC, and OnLocation, July 1997.)

*Abstract*

This paper, the last in a series of three papers on distributed resource (DR) technologies, describes proposals for addressing the barriers to market penetration of distributed resource technologies, and provides a modeling framework to evaluate these proposals.

*Legislative, Policy, or Programmatic Proposals to Lower Market Barriers*

This section provides a summary and evaluation of some proposals that have been advanced to address and lower barriers to the market penetration of DR resources. The proposals discussed address: (1) strategies for dealing with the high cost of DR options relative to the low electricity cost consumers are accustomed to paying; and (2) the need to ensure that codes and standards are written in ways that enable DR technologies to enter the generation mix with adversely impacting power quality and system reliability. The proposals include:

Green Pricing
Code and Standard Revisions
Technology Cost Buy-Down Through Subsidies
Technology Valuation Based on Avoided Generation Costs or Environmental Benefits

*Framework for Quantitative Analysis*

This section discusses alternative modeling frameworks for distributed generation market penetration and emission impacts.

*Generic Distributed Generation Modeling Issues*. Distributed generation lies at the intersection of the demand and supply for electricity. Distributed generation technologies could potentially be purchased by energy users, by electricity generators, by transmission operators, by distribution companies, or by third-party ESCOs. Although the new deregulated electricity market should provide unbundled price signals that are similar to marginal costs, the actual market for distribution may still be regulated monopolies. These may charge connection costs for isolated loads that are at less than full marginal cost and customers may also be able to use the political process to require that distribution cost are charged more on an average cost basis.

At the heart of a market penetration model is an economic representation of the technology and its competing alternatives. Several characteristics of each technology would be represented: capital cost, siting and construction time, operating cost, efficiency (if appropriate), technological risks/reliability, and emissions. Non-economic factors and the customer’s perspective would be included to the extent possible. If grid connected, there might be fixed transmission and distribution costs. With this information the cost of the distributed generation can be compared to the alternative cost of providing the electricity from a central station resource. This alternative cost would be represented by the generation cost, wholesale power transmission charge, and a distribution charge.

*National Level Model*. The natural starting point for developing a new model is to start with a utility model or a utility sector of an integrated model and add a distributed generation sector. The key requirement of the utility model is that it can provide unbundled electricity rates. It will also be desirable to represent the variability in distribution costs (which spatial studies show can vary significantly even within a single utility) because it is the high end of cost where distributed generation will be most cost-effective.

The desired disaggregation of the demand sector is the use of electricity by commercial vs. industrial, by existing vs. new, by load size, by generic load shape, and by locality (urban, suburban, and rural). (Residential customers are unlikely to have significant DR choices and make large investments.)

Optimization and simulation models each have advantages and disadvantages for distributed generation modeling. Simulation models can usually incorporate more heuristics and a better representation of market barriers in their structure. Optimization frameworks allow straightforward cost comparisons across technologies and time, can incorporate perfect foresight, but will choose a single least cost technology with each market that is defined. Because markets for distributed generation depend on the high end of cost distributions a simulation model with logistic type algorithms would be most suitable.

Several existing national level models are available, but the best starting point considering the criteria above is probably NEMS with its existing electricity and demand modules, with an added distributed generation module.

*Regional Level Model*. Most of the considerations here are similar to those above.

*Utility Level Case Study Model*. Many of the considerations here are similar to those above. There are a variety of utility models that might be built upon, but they typically are expensive, hard to build on, are optimizing, and typically put most effort into generation, not distribution. The first step would be a detailed review of existing models.

*Screening Tool Model*. This would most likely be a spreadsheet model that could compare distributed generation technology costs with alternative assumptions about electricity purchased costs.

*Overall Recommendation*. For the purposes of the customer of this report the recommendation for the first cut is the screening tool model.

## Defining Distributed Resource Planning

(Article written by Charles D. Feinstein and Jonathan A. Lesser, in The Energy Journal, special issue on Distributed Resources in 1997)

*Abstract*

The concept and objectives of distributed utility planning, sometimes called distributed resource (DR) planning, are unclear. this paper provides a cogent definition of DR planning and explains some of the emerging fallacies over its purpose.  the objective of DR planning should be to meet customers' capacity needs at the lowest expected future cost by determining an optimal investment strategy for a given area. Many advocates of DR planning have erroneously defined the objective as deferral of "traditional" transmission and distribution facilities, and have developed methodologies to determine maximum deferral times.  Defining the DR planning objective in this manner will always lead to higher than necessary costs, because cost-minimization is not addressed in an appropriate manner.  In general, deferral methodologies have misspecified the objective function, used quantitative tools inappropriately, and, perhaps their most critical shortcoming, failed to incorporate the effects of uncertainty on the optimal investment strategy. The solution is to treat deferral as a consequence of developing a least-expected-cost distribution plan, rather than treating deferral as an objective in itself.

In this article they spend some time discussing and critiquing the mathematics of the use of the MDCC measure (cited in another article above) as defined by Orans (1991), Woo (1995) and Hoff (1996).  Their conclusion is that the solution used by these three is inconsistent with a least-cost investment policy.

**Using Distributed Resources to Manage Risks Caused by Demand Uncertainty**

(Article written by Thomas Hoff, in The Energy Journal, special issue on Distributed Resources in 1997)

*Abstract*

This paper presents a method to calculate the cost of satisfying transmission and distribution (T&D) system capacity needs as a function of investment modularity and lead-time.  It accounts for the dynamic nature of demand uncertainty, the decision-maker's risk attitude, and the correlation between costs and firm profits.  Results indicate that the modularity and short lead-times associated with the distributed resources can increase their attractiveness in comparison to long lead-time, large-scale T&D investments.  Results also suggest that distributed resources can operate as a type of "load growth insurance" if demand growth is positively correlated with profits (so that costs are incurred when profits are high) and if the distributed resource costs are part of a larger portfolio that cannot be diversified.

The author writes that electric utilities have become increasingly reluctant to invest in long lead-time, large-scale power generation projects for several reasons.  First, facilities have often cost more and taken longer to construct than initially anticipated.  Second, actual demand has often not met expectation with the result that the investments were unnecessary.  Third, the investments have had a greater financial risk than initially anticipated because: a) regulatory commissions viewed them as imprudent and prevented full cost recovery in some cases; and b) competition from lower cost suppliers prevented full cost recovery in other cases.  The result is that generation investments have shifted away from long lead-time, large-scale generation to short lead-time, modular generation.

**Operation and Control in a Competitive Market:   Distributed Generation in a Restructured Industry**

(Article written by Judith Cardell and Richard Tabors, in The Energy Journal, special issue on Distributed Resources in 1997)

*Abstract*

The prospect of independent ownership for distributed technologies is being encouraged by the current deregulation of the industry, and it is possible that the new generators will be independently operated as well as independently owned. The siting of numerous small-scale generators in distribution feeders is likely to have an impact on the operations and control of the power system, a system designed to operate with large, central generating facilities. In response to the new and potentially conflicting economic and technical demands of a growing number of independent players, the power system may require new means for coordinating system operations. Price signals are one mechanism available to coordinate the operation of the power system in the emerging competitive market. This paper discusses the integration of distributed generation in to the operations of the distribution system. It first discusses the engineering concern that numerous distributed generators might adversely impact system stability and reliability, and proposes methods to address these issues. the paper then demonstrates the ability of the distributed generators to participate in the competitive energy and ancillary services markets, by responding to a price signal that coordinates both the engineering and the economic aspects of distributed generator operation in a restructured power system.

### Identifying Distributed Generation and Demand Side Management Investment Opportunities

(Article written by Thomas Hoff, in The Energy Journal, Vol 17, No. 4, 1996)

*Abstract*

Distributed generation and targeted demand side management programs offer electric utilities alternatives to large transmission and distribution (T&D) system capacity investments. this paper presents a method to estimate how much a utility can afford to pay for these alternatives when the change in system capacity due to the distributed resource is constant from year to year and when there is no uncertainty. The method is concise, has intuitive appeal, has minimal data requirements, and is accurate when benchmarked against two existing case studies. Analysts who want to screen distributed resource investment opportunities with a minimal amount of effort will find the method particularly useful.

### Marginal Capacity Costs of Electricity and Demand for Distributed Generation

(Article written by Chi-Keung Woo, Debra Lloyd-Zannetti, Ren Orans, Brian Horii, and Grayson Heffner, in The Energy Journal, Vol 16, No. 2, 1995)

*Abstract*

Marginal costs of electricity vary by time and location. Past researchers attributed these variations to factors related to electricity generation, transmission, and distribution. Past authors, however, did not fully analyze the large variations in marginal distribution capacity costs (MDCC) by area and time. Thus, the objectives of this paper are as follows: (1) to show that large MDCC variations exist within a utility's service territory; (2) to demonstrate inter-utility variations in MDCC; and (3) to demonstrate the usefulness of these costs in determining demand for distributed generation (DG).

Marginal costs of electricity service vary by time and area of service. Time-varying marginal costs are due to the least-cost planning and operation of a generation system. Marginal costs vary by location because of (I) area-specific constraints in a generation system; and (ii) line losses, reactive power and capacity constraints in a transmission network. Cost dispersion by location is also attributable to variance of marginal distribution capacity costs (MDCC). In the past, utilities were mainly concerned with the generation and bulk transmission system. In recent years, however, the ratio of local transmission and distribution expenditures to total capital expenditures has increased dramatically. Area- and time-specific marginal costs (ATSMC) are valuable in targeted resource pricing and planning. There are two questions: (I) how dispersed are marginal costs within a utility and across utilities? and (ii) what is the economic potential for DG? These two are closely related. If the marginal costs are widely dispersed within a utility, then there likely exist high-cost areas for which DG is economical.

This paper analyzes the demand for DG by two U.S. utilities, PG&E (California) and PSI (Indiana) and has two major findings. First, MDCCs vary by utility and over time and it is this area- and time-specific nature of the MDCCs that drives the DG demand. Second, the demand for DG confirms that a system-wide implementation of DG is generally not cost-effective and DG should only be targeted at areas with high MDCCs that are caused by significant distribution investments in areas with moderate growth in electricity demand.