Appendix E-5[1]

METHODOLOGY FOR CHP IMPACT ESTIMATES USING THE DISPERSE MODEL[1]

1. PURPOSE AND CONTEXT

The CEF-NEMS model bases the growth in Combined Heat and Power (CHP) on incremental changes in steam demand, and does not allow for retirement of existing boilers. The policies that are proposed for the Moderate and Advance Scenarios are designed to have a broader impact on CHP growth, and are intended to replace, where economical, existing boilers. To capture the impact of such policies, the modeling of CHP growth in the industrial sector is accomplished outside of the NEMS model. In addition, the approach is tailored so that the results feed back into the CEF-NEMS framework, and thus ensures consistency with other CEF analyses.

2. OUTLINE OF THE APPROACH

The CHP analysis of the industrial sector was performed using the Resource Dynamics Corporation s DIStributed Power Economic Rationale SElection (DISPERSE) model. This model has been developed over the past five years, and has been used for a variety of projects for utilities, equipment manufacturers, and research organizations. One of the strengths of the model is its flexibility in addressing a wide range of potential scenarios, including sensitivity analysis, business strategy planning, and policy study. The approach for the CEF analysis was to adjust the inputs (i.e. prices, steam demand, and other parameters impacted by the policies) as appropriate to model the CEF Scenarios.

The DISPERSE model estimates the achievable economic potential and expected market penetration for distributed generation by comparing on-site generation economics with competing grid prices. The model not only determines whether on-site generation is more cost effective, but also which technology and size appears to be the most economic. As a result, double counting of market potential for a variety of competing technologies is avoided. The model then applies a market penetration scenario that best fits the objectives of the analysis, and thus estimates the policy impact on the rate of on-site generation growth.

The number of potential applications is determined using data on number of industrial facilities in each industry, size range, and state. Results are aggregated and summarized to show key information on where the potential applications are (e.g., the top state for industrial sector applications of 20-50 MW gas turbines is California, and almost all the applications are combined heat and power). Figure E-5.1 provides an overview of the model inputs, analysis, and output.

The model run begins with a database of industrial sites, which are organized by state, SIC code, and size (in terms of number of employees). Based on site location and the natural gas costs database, the model determines whether natural gas is available to the site. In addition, based on the site SIC code, the model assigns a load profile which is representative of that industry. The size of facility is used to scale up or down the magnitude of the load profile.

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[1] Authors: Paul Lemar (Resource Dynamics Corp.). Marilyn Brown (ORNL) provided assistance with the analysis of energy and carbon impacts.

Using this information, combined with the unit price and performance data, the model performs a discounted cash flow analysis, based on the unit life as well as the cost and performance data, and state fuel prices. The model determines the lowest cost distributed power option based on yearly costs to generate and expected escalation rates.

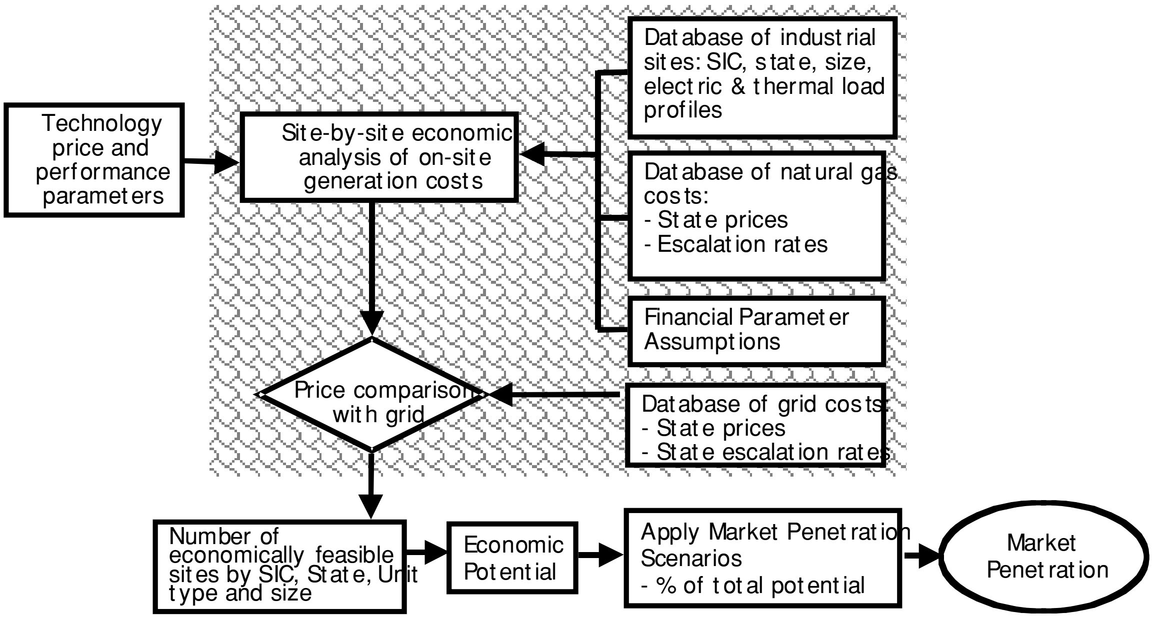


Fig. E-5.1 DISPERSE Model

The model then compares the cost to generate over the life of the project with costs of purchasing from the grid (from the database of grid prices), and counts the application if it beats the grid price. This process is repeated tens of thousands of times, once for each group of sites with the same state/size range/SIC code in the database of industrial sites, and the results are then aggregated to obtain market potential.

Penetration of the market by CHP projects will more or less follow a classical S-shaped logit curve, reflecting limited early adoption, more rapid market penetration as the market approaches maturity, and a flattening of the curve as the market matures and the penetration rate slows. The exact shape and magnitude of the curve is the major uncertainty. The model applies one or more market penetration curves which are selected on the basis of their fit with the scenario being modeled.

In addition to considering conventional gas-fired CHP units, the CEF-DISPERSE model estimates the impact of biomass in the pulp and paper industry. Opportunities for other industries were considered, including the food products and lumber industries, but it was decided that the pulp and paper industry offered the most potential CHP capacity, and was furthest along in terms of developing the necessary technology. The model approach includes analysis of black liquor gasifier/combined cycle (BLGCC) and biomass gasification/combined cycle (BGCC) units.

3. MODEL INPUTS FOR MARKET POTENTIAL

To determine market potential, the following data are baseline inputs used by the model:

1. **Technology price and performance parameters**. The model requires data on the mix of technologies that are being made available to the sites analyzed. This data includes their installed cost, fuel type, heat rate, electrical efficiency, useable thermal output, fixed and variable operating and maintenance costs, and other key parameters. This data (see Table E-5.1) is derived from manufacturer-provided data, and is validated by comparison with published data in journals, technical papers, and other sources. All data is for natural gas fueled units (data for biomass and black liquor gasifier/combined cycle units is presented in Section 5).

2. **Database of industrial sites**. Data on number of customers in each SIC and size range are from the Department of Commerce Country Business Patterns and the Manufacturing Energy Consumption Survey. Data for pulp and paper mills is taken from the Lockwood Post Post's Directory of the Pulp, Paper, and Allied Trades. Electricity use per employee is taken from the Annual Survey of Manufactures (U. S. Bureau of the Census). Industrial sector potential for combined heat and power is based on process level steam and hot water demand data from the RDC Industrial Market Information System (IMIS). Load profile data is from RDC-collected load profiles as well as Lawrence Berkeley National Laboratory data on electric and thermal profiles, by SIC and climate region.

3. **Database of fuel prices**. Natural gas costs are based on state averages, as reported by EIA. Facilities with units over 1 MW are given access to electric utility rates, with smaller units using industrial rates. Natural gas escalation rates are based on EIA projections from the Annual Energy Outlook, with alternative scenarios drawing from other sources.

4. **Financial parameter assumptions**. Ownership parameters are based on RDC experience with typical DG projects, and expectations for financial structures of projects in the future. Much of this information is based on experience from operating RDC s lease financing subsidiary company, EFS Finance, which finances energy projects including on-site generation. See Table E-5.2 for a list of these assumptions.

Table E-5.1 Unit Price and Performance Characteristics

Size	45-75kW		75-150kW	
Type	Recip	MT	Recip	MT
Cost ($/kW)	770	800	730	800
O&M ($/kWh)	0.0100	0.0100	0.0090	0.0100
Elec. Eff.	31.0%	27.1%	31.7%	27.1%
Heat Rate (Btu/kWh)	11,000	12,600	10,800	12,600
Therm. Out. (MMBtu/hr)	0.27	0.36	0.54	0.73
Overall Eff.	80.0%	85.0%	82.0%	85.0%

Size	150-350kW			350-750kW		
Type	Recip	MT	FC	Recip	MT	FC
Cost ($/kW)	690	700	3300	640	700	3300
O&M ($/kWh)	0.0085	0.0090	0.0150	0.0080	0.0090	0.0150
Elec. Eff.	32.5%	27.1%	39.6%	35.0%	27.1%	39.6%
Heat Rate (Btu/kWh)	10,500	12,600	8,620	9,750	12,600	8,620
Therm. Out. (MMBtu/hr)	1.1	1.5	0.75	2.5	3.7	1.9
Overall Eff.	84.0%	85.0%	83.1%	87.0%	85.0%	83.1%

Size	.75-5MW		5-10MW	
Type	Recip	Turbine	Recip	Turbine
Cost ($/kW)	600	600	550	480
O&M ($/kWh)	0.0075	0.004	0.007	0.004
Elec. Eff.	38.0%	25.5%	42.0%	31.0%
Heat Rate (Btu/kWh)	8,980	13,400	8,120	11,000
Therm. Out. (MMBtu/hr)	11	20	28	47
Overall Eff.	85.0%	85.0%	87.5%	87.5%

Size	10-20MW	20-50MW		50-100MW		100+MW	
Type	Turbine	Turbine	CC	Turbine	CC	Turbine	CC
Cost ($/kW)	480	400	860	340	770	270	600
O&M ($/kWh)	0.004	0.004	0.005	0.004	0.005	0.004	0.005
Elec. Eff.	33.0%	36.5%	47.0%	36.5%	49.5%	36.5%	53.0%
Heat Rate (Btu/kWh)	10,300	9,350	7,260	9,350	6,890	9,350	6,450
Therm. Out. (MMBtu/hr)	88	180	110	380	210	500	240
Overall Eff.	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%	90.0%

Source: RDC estimates based on manufacturer literature and Gas Turbine World.

Key:

Recip-	reciprocating engine
MT -	microturbine (combustion turbine less than 750kW)
Turbine -	combustion turbine
FC -	fuel cell
CC -	combined-cycle plant (combustion and steam turbine)

Table E-5.2 Financial Parameters

Project Length (years)	20
Federal Income Tax (%)	35
State Income Tax (%)	5
Property Tax (%)	1.5
Insurance Rate (%)	0.5
Debt Repayment Period (years)	20
Common Equity Fraction	0
Debt Fraction	1
Return on Debt (%)	9.1
Discount Cash Flows (%)	7

5. **Database of grid prices**. Electric prices are based on current utility-by-utility grid prices (EIA). Typical grid backup charges are added. Escalation rates are based on AEO 99 projections (EIA), with adjustments for the progress of restructuring in the states which are farthest along in the process.

4. MODEL INPUTS FOR MARKET PENETRATION

To obtain the expected impacts of the CEF Scenarios, market penetration rates are applied to the estimates of market potential. These rates are used to translate what share of the acheivable economic potential will be realized with each of the three CEF Scenarios. It is generally accepted that penetration of the market by any new technology or existing technology with market barriers removed will more or less follow a classical S-shaped logit curve. This curve will reflect three general sequential stages: 1) limited early adoption, 2) more rapid market penetration as the market approaches maturity, and 3) a flattening as the market matures and the penetration rate slows. The exact shape and magnitude of the curve is the major uncertainty.

A unique historical opportunity presents itself to model the market penetration expected from the CEF Scenarios. Almost exactly 20 years ago, the Public Utility Regulatory Policies Act (PURPA) was enacted. PURPA was one part of the effort to solve what was perceived as a nationwide energy crisis. In 1978, Congress enacted omnibus legislation intended to provide for increased conservation of electric energy and increased efficiency in the use of facilities and resources by electric utilities. PURPA was an integral element of this legislation, and serves as a model for the expected penetration of CHP into the market. The policies and programs associated with the passage of PURPA offer striking parallels with the Advanced CEF Scenario.

Cogeneration is the foundation of combined heat and power (CHP), and has been used by industry and business for many years. Prior to the enactment of PURPA, a cogeneration or small power production facility seeking to establish interconnected operation with an electric utility faced three major obstacles. First, an electric utility was not generally willing to purchase the electric output or was not always willing to pay a fair price for that output. Second, some electric utilities charged discriminatorily high rates for back-up service to cogeneration and small power production facilities. Third, generators that provided electricity to an electric utility s system risked being considered a public utility and subjected to extensive and costly state and Federal regulation. Prior to PURPA, the traditional use of cogeneration did not entail selling output to the local utility.

In PURPA, Congress recognized the potential of cogeneration and small power production to increase energy efficiency and reduce reliance on imported oil. PURPA established specific utility obligations for dealing with cogenerators while providing significant incentives for cogeneration and other forms of alternative energy production. PURPA fostered changes in the way in which electricity is generated in the United States, and signaled the beginning of a structural shift in the energy markets.

PURPA authorized FERC to establish the rules by which utilities deal with cogenerators. It required state agencies to establish (with federal guidelines) rules governing the interconnection of electric utility systems with cogenerators as well as the rates at which power exchanges between utilities and cogenerators may occur. PURPA also removed regulatory and economic obstacles to cogeneration and small power producers who use certain renewable or alternative fuels. While it is recognized that a number of barriers still exist, PURPA has resulted in a dramatic increase in CHP capacity from 1977-1997.

Figure E-5.2 illustrates the 20 year trend in industrial cogeneration, depicting both actual growth in traditional and non-traditional units, as well as DISPERSE market potential predictions based on 1977 data on unit cost and performance and industrial energy demand and prices. The DISPERSE estimate for market potential for traditional applications (52 GW) is based on no output sold back to the local utility, whereas the traditional plus non-traditional application prediction (96 GW) is based on sales back to the grid (using prevailing sell-back rates).

In the Business As Usual (BAU) scenario, the model assumes that growth in non-traditional units has been curtailed due to remaining barriers, and the only growth in CHP units will be from traditional applications. This is consistent with the trend shown in Figure E-5.2, as well as published BAU forecasts from EIA and the Gas Research Institute. In deriving the expected rate of penetration, however, the DISPERSE BAU uses the period from 1983-1993 as indicative of future growth. This is to avoid the early period (1977-1983) when the utility industry had overestimated demand growth, and was constructing excess capacity, which caused industrial firms to reevaluate their cogeneration projects. Similarly, the 1993-1997 timeframe was affected by electric utility restructuring, which again has caused industrial establishments to reconsider plans to develop new CHP capacity. Projecting the 1983-1993 growth over the 2000-2020 timeframe, a market penetration level of 18 percent is forecasted.

In the Advanced Scenario, the model adopts the 20-year penetration rate presented by PURPA, with two modifications (see Figure E-5.2). First, the growth in new capacity is expected almost immediately, as a result of accumulated demand for new CHP units that have been delayed by restructuring uncertainty. Secondly, the end of the period is not expected to be plagued by the restructuring uncertainty which slowed the Actual PURPA growth, and thus curve shows continued growth in the 15-20 year timeframe. The market penetration level attained in the Advanced Scenario reaches 56 percent (54 GW of new capacity versus 96 GW predicted) by the year 2020. New capacity is derived by subtracting existing capacity in 1977 (7GW) from the new level of 61GW in 1997.

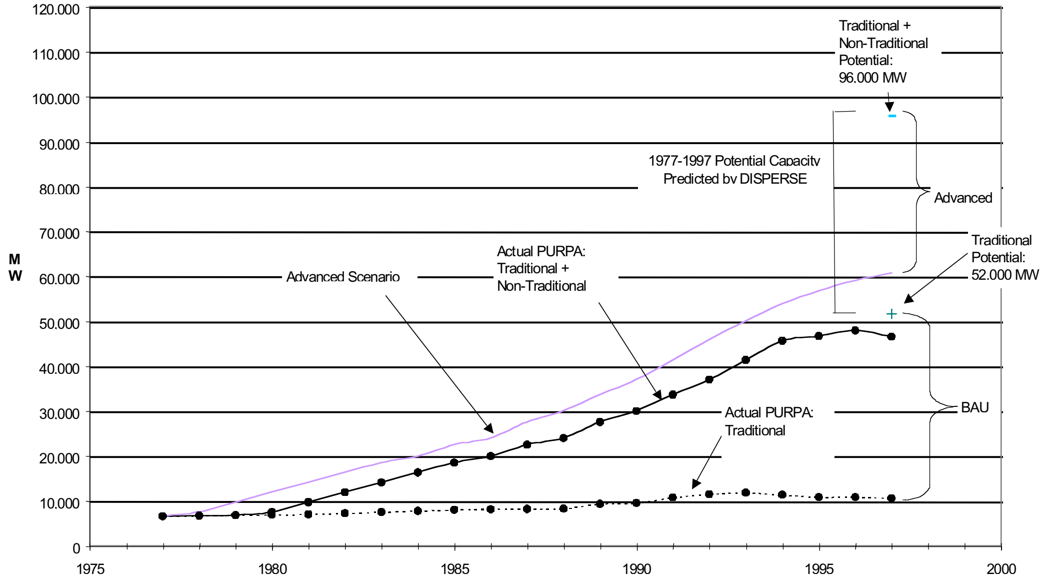


Fig. E-5.2 Growth Rates for Industrial CHP Capacity

5. MODEL MODIFICATIONS FOR THE CEF SCENARIOS

5.1 Business As Usual (BAU) Scenario

- AEO 99 Natural Gas Price Escalation used
- AEO 99 Electric Escalation used as a basis; escalation rates were adjusted by state; states with the highest current prices and furthest along in deregulation were adjusted more significantly
- Buy-back price average of 50% of retail price. Regional variations as follows (NCASI 1998): BAU average value consistent with GRI 1997.

Area	Buy Back (%of Retail)			States Included
	BAU	Moderate	Advanced	
South	29%	60%	80%	West South Central, East South Central, South Atlantic, AZ, NM
North West	70%	70%	80%	Pacific (exc. HI), ID, MT, NV, UT
North East (other than NJ and NY)	30%	60%	80%	New England, PA
NJ&NY	56%	60%	80%	NJ, NY
North-Central	76%	76%	80%	West North Central, East North Central, CO, WY
Average	**50%**	**64%**	**80%**	

- Market penetration based on 1983-1993 growth rate in traditional CHP units (see Figure E-5.3)

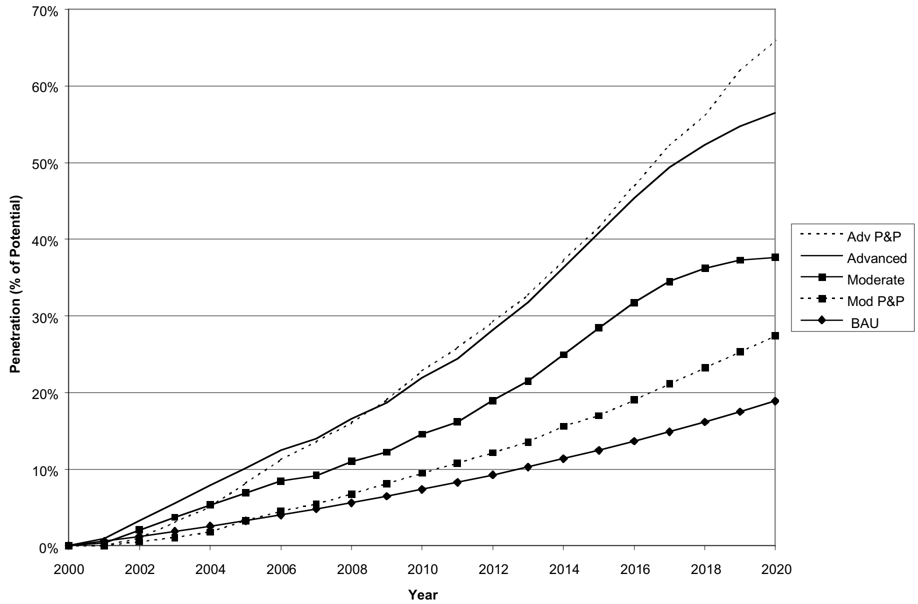


Fig. E-5.3 Modeled Growth Rates for Industrial CHP Capacity

5.2 Moderate Scenario

- Natural Gas and Electricity price escalations from CEF-NEMS Moderate Scenario
- Changes in electric demand, and steam demand taken from NEMS-CEF Moderate Scenario and used to scale model inputs (see Figures E-5.4 & E.5.5)
- Buy-back price increased to 60% of retail price (regional variations incorporated, see table above)
- Black liquor gasifier/combined cycle (BLGCC) and biomass gasifier/combined cycle (BGCC) units become available for pulp and integrated mills based on the following data:
  - Plant pulp and paper production by process from plant data (Lockwood-Post, 1996).
  - Steam and electricity use calculated on process-specific energy consumption per unit of product (EPRI, 1988)
  - 90% Unit Capacity Factor

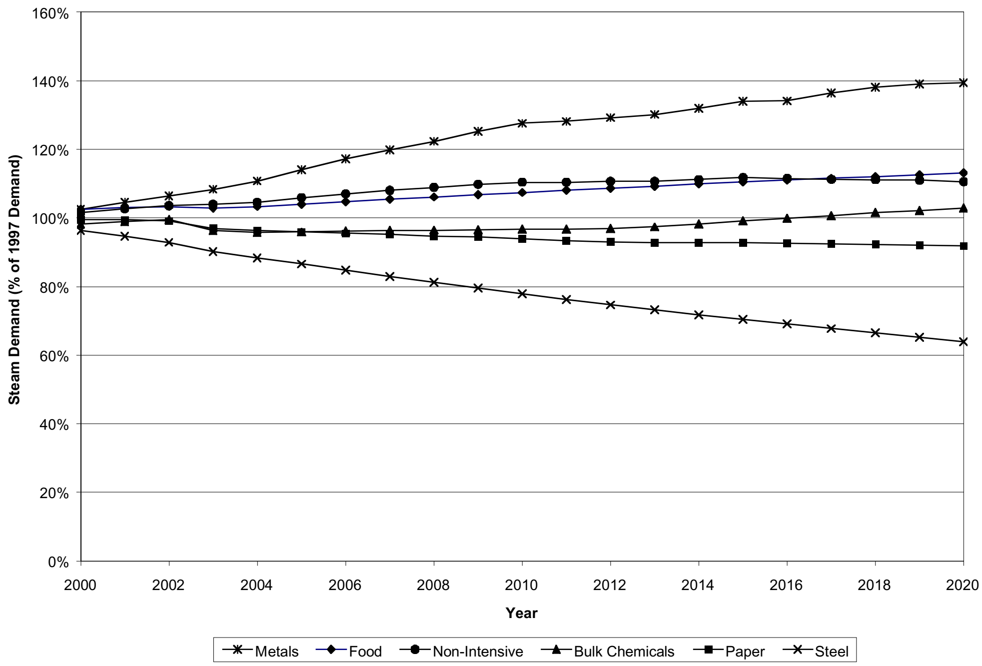


Fig. E-5.3 Modeled Growth Rates for Industrial CHP Capacity

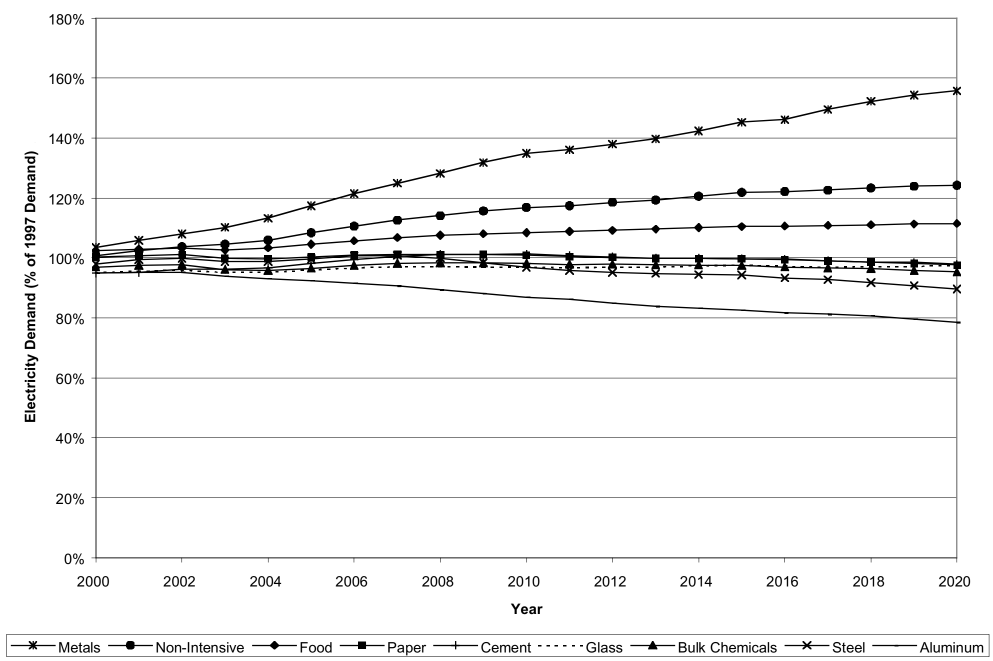


Fig. E-5.5 NEMS Moderate Scenario Predicted Electricity Demand by Sector

Unit Characteristics (Larson, 1998; NREL/EPRI, 1995):

	Kraft Mills			Other Paper Mills	
	Base Case: Tomlinson+Bark Boiler	Indirect-BLGCC + Bark Boiler	Indirect-BLGCC + BGCC	Base Case: Bark Boiler	BGCC
Biomass (tpd)	395	950	3878	1826	720
Electric (MW)	46.8	129	212	39	0
Cost (Million)	138.71	167.36	302	78.32	21.1
Cost ($/kW)*	2964	1297	1428	2008.21	N/A
Biomass Fuel Cost (Million)	4.32	15.26	20	9.33	3.68
Biomass Fuel Cost ($/kWh)	0.0062	0.0150	0.0107	0.0273	N/A
Fixed O+M ($1000/yr)	2900	3260	11022	3656	1902
Variable O&M ($1000/yr)	2200	2870	4141	1533.5	1847
Fixed O&M ($/kW)	61.97	25.27	52.04	93.74	N/A
Variable O&M ($/kWh)	0.0060	0.0026	0.0025	0.0050	N/A
Steam Output	910	910	910	272	272

- Incremental cost versus base case assumed based on replacement when necessary
- Market penetration to start with 2 demonstration projects by 2002, with penetration of 27 percent by 2020 (Based on 40 year penetration to 90% of total potential). See Figure E-5.3.

- ATS turbines become available in 2005 at $750/kW (dropping to $450/kW by 2020) and made available for applications 5-20MW.
- Market penetration of conventional CHP units based on blend of BAU and Advanced scenario penetration (See Figure E-5.3)

- Moderate policy effects incorporated as follows:

Policy Goal	Moderate Scenario	Model Adjustments
Expand CHP R&D Portfolio	CHP/DG technology development budget will increase by 50%, focusing on increased efficiency, reliability improvement, and cost reduction.	Increase efficiency and/ reduce costs for ATS ($750 to $450/kW) and Micropower units in the model. Make BLGCC and biomass gasification technology available.
Remove Financial Barriers	Implement tax credits included in Administration s FY2000 Budget Proposal; by 2002 shorten CHP equipment asset life	Tax credit - give credit (8% of project cost) in Year 1 based on CCTI requirement for use of thermal output and minimum system efficiency; Shorten assessment life — shorten depreciation schedule from 15 to 7 years.
	Expedited certification of CHP project meeting efficiency and heat/power share criteria to qualify for tax incentives; self-qualification of facilities for financial incentives	Shorten time between project implementation and tax credit from one year to six months.
Expedited Siting and Permitting for CHP Projects	By 2002 provide guidance to state agencies on establishing faster CHP permitting processes, encouraging arrival of new capacity online earlier (EPA Handbook and workshops)	Reduce time and expense associated with permitting. <1 MW: 8 wks to 4wks; ~$60,000 to $40,000 1 MW to 15 MW: 6 mths to 3 mths; ~$114,000 to $76,000 >15 MW: 1 yr to 6 mths; ~$225,000 to $150,000
Remove Utility Barriers	1. By 2002, enactment of national interconnection standard for CHP and other distributed generation projects 2. Government support of advanced interconnection packages/ technologies, leveraging on industrial R&D to realize moderate installed cost	Reduce time and expense associated with interconnection. <1 MW: 4 wks to 2 wks; ~$20,000 to $15,000 1 MW to 15 MW: 2 _ mths to 1 _ mths; ~$35,000 to $26,250 >15 MW: 3 mths to 1 _ mths; ~$40,000 to $30,000
	Mandated availability of backup power at reduced cost, or customer shopping for competitively-priced backup power	Reduce Back-up charges (lower 20%) Improve buyback rates to 60% of retail

5.3 Advanced

- Natural Gas and Electricity price escalations from CEF NEMS Advanced Scenario were incorporated
- Changes in electric demand and steam demand taken from CEF NEMS Advanced Scenario and used to scale model inputs (See Figures E.5.6 & E.5-7)
- Buy-back price increased to 80% of retail price (see table above)
- Black liquor gasifier/combined cycle units become available for pulp and integrated mills based on the data presented in Moderate scenario, with one exception: market penetration based on 90% of potential reached in 30 years - 66 % by 2020.
- ATS turbines become available in 2005 at $550/kW (falling to $350/kW by 2020) and are made available for applications 5-50MW.
- Market penetration based on 20 year impact of PURPA on traditional and non-traditional CHP applications (see Figure E-5.3)

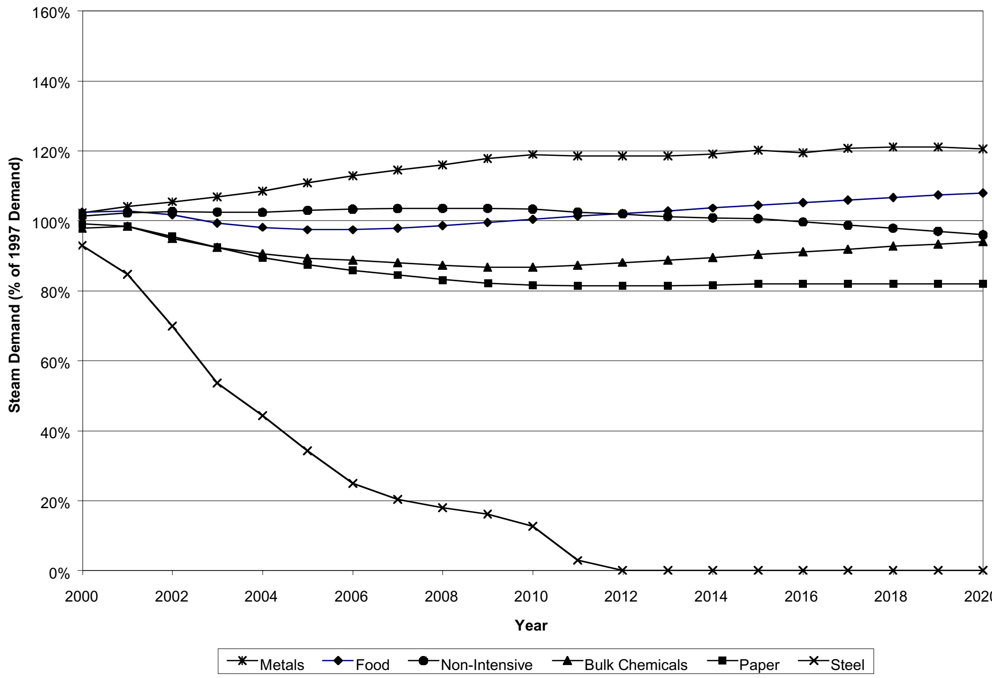


Fig. E-5.6 NEMS Advanced Scenario Predicted Steam Demand by Sector

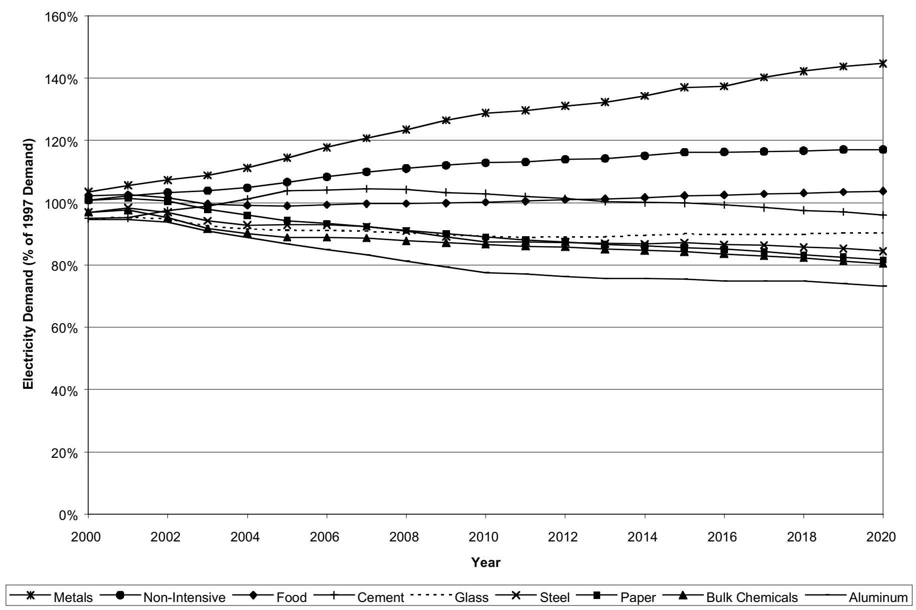


Fig. E-5.7 NEMS Advanced Scenario Predicted Electricity Demand by Sector

- Advanced policy effects incorporated as follows:

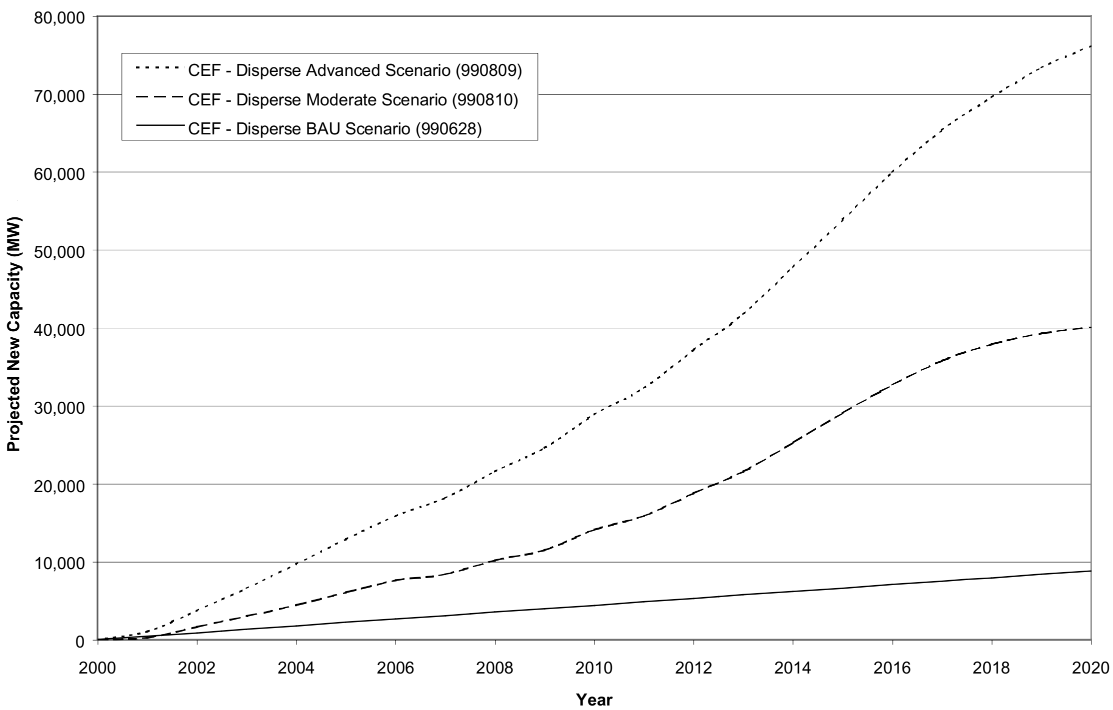
Policy Goal	Advanced Scenario	Model Adjustments
Expand CHP and DG R&D Portfolio	Doubling of CHP/DG technology development budget, focusing on increased efficiency, reliability improvement, and cost reduction, all at levels beyond current anticipated 2010 performance goals	Further increase efficiency and/or reliability and/or reduce costs for ATS ($550 to $350/kW) and Micropower units in the model. Make BLGCC and biomass gasification technology available at incremental cost.
Remove Financial Barriers	Extend tax credits beyond 2003 and allow accelerated depreciation on remaining basis of property	Tax credit — give credit (8%) in Year 1 based on CCTI requirement for use of thermal output and minimum system efficiency. Shorten assessment life — shorten depreciation schedule from 15 to 7 years.
	Expedited certification of CHP project meeting efficiency and heat/power share criteria to qualify for tax incentives; self-qualification of facilities for financial incentives	Shorten time between project implementation and tax credit from one year to six months.
Expedited Siting and Permitting for CHP Projects	Through Clean Air Partnership Fund, 1)˚increase state grants to encourage streamlined CHP siting and permitting, and 2) favor grants to states with accelerated CHP siting and permitting	Reduce time and expense associated with permitting. <1 MW: 8 wks to 4wks; ~$60,000 to $30,000 1 MW to 15 MW: 6 mths to 3 mths; ~$114,000 to $57,000 >15 MW: 1 yr to 6 mths; ~$225,000 to $112,500
Remove Utility Barriers	1. By 2002, enactment of national interconnection standard for CHP and other distributed generation projects 2. Government support of advanced interconnection packages/technologies, leveraging on industrial R&D to realize very low installed cost	Reduce time and expense associated with interconnection. <1 MW: 4 wks to 2 wks; ~$20,000 to $10,000 1 MW to 15 MW: 2 _ mths to 1 _ mths; ~$35,000 to $17,500 >15 MW: 3 mths to 1 _ mths; ~$40,000 to $20,000
	Mandated availability of backup power at reduced cost, or customer shopping for competitively-priced backup power	Reduce Back-up charges (lower 20%) Improve buyback rates to 80% of retail

MODEL RESULTS

The model estimates CHP potential for year 2020 ranging from 46 to 133 GW, permitting retirement of existing boilers where economically feasible. These estimates include both traditional (where all unit output is used on-site) and non-traditional (where sale of electricity to the grid is permitted) applications of CHP, and is limited to industrial sector applications. District energy applications of CHP are not included in this sector, and are considered in the buildings sector analysis.

As shown in Figure E-5.8, the market penetration is estimated to be between 9 and 76 GW, and depends on the timing and impact of CHP policies designed to remove technical and market barriers (see Section 4). In the BAU scenario (see Table E-5.3), 8.8 GW of new CHP is projected, based on a market potential of over 46 GW and a continuation of current market penetration trends. Several technical and market barriers stand in the way of further use of CHP, as evidenced by the fact that over 80 percent (38 GW) of the potential capacity is projected as untapped.

Fig. E-5.8 Projected CHP Market Penetration



In the moderate scenario (see Table E-5.3), the projected new CHP grows to 40 GW. This is based on an expanded year 2000 market potential of 96 which jumps to 120 GW in 2020 largely due to the introduction and improvement of ATS turbines. This market includes 19 GW of potential biomass capacity in the pulp and paper industry. In this scenario, it is expected that expanded research and development will result in black liquor gasified combined cycle technology by 2002, which will result in two demonstration projects by 2002 and an installed base of 5.2 GW by 2020. In addition, this expanded R&D will result in the emergence of high efficiency gas turbines (resulting from the ATS program and efforts targeting the under 1 MW unit size) which is expected to increase CHP capacity in under 5 MW unit size ranges. Furthermore, policies designed to remove financial barriers, expedite siting and permitting, improve grid sell back price, and reduce interconnection costs are expected to contribute significantly to the expanded market potential and penetration. These policies combine to improve the expected market penetration level to approximately 37 percent (40 of 96-120 GW).

In the advanced scenario (see Table E-5.3), the projected level of new CHP reaches 76 GW. Accelerated development of black liquor gasified combined cycle units as well as cost and efficiency improvements in 5 MW and under gas turbines contribute significantly to the 123-133 GW (2000-2020) of market potential. The lower split between year 2000 and 2020 in the advanced scenario (10GW vs. 24GW in the moderate scenario) is due to a number of factors, most notably the projected reduction in steam demand in the advanced scenario. More aggressive policies designed to remove financial barriers, expedite siting and permitting, improve grid sell back pricing, and reduce interconnection and backup power costs all contribute to improved market penetration levels of 56 percent.

Table E-5.3. Projected CHP Impacts

Market Impact	Projected Impacts (Year 2010)			Projected Impacts (Year 2020)		
	BAU	Moderate	Advanced	BAU	Moderate	Advanced
New Capacity (GW)	4.4	14.1	28.9	8.8	40.1	76.2
Natural Gas	4.4	12.3	24.5	8.8	34.9	63.6
BLGCC	0	1.1	2.6	0	3.1	7.5
BGCC	0	0.7	1.8	0	2.1	5.1
Generated Electricity (TWh)	30.9	98.3	201	61.7	278	539
Fuel Consumed by CHP Systems (TBtu)	274	901	1,853	551	2,542	4,985
Of which: natural gas	274	793	1,595	540	2,232	4,237
Of which: biomass	0	108	258	11	310	747

7. ENERGY IMPACTS

An off-line analysis of CHP in industry was conducted in order to estimate the overall impact of expanded CHP capacity on primary energy consumption and carbon dioxide emissions.

The impact of new CHP systems on primary energy consumption and carbon dioxide emissions is a function of three factors:

1. The fuel displaced at electric utilities,
2. The boiler fuel displaced in the industrial sector, and
3. The fuel used by the CHP units.

Each of these is discussed in turn.

(1) The fuel displaced at electric utilities

Table E-5.3 estimates the new CHP capacity and generated electricity (above the BAU forecast) that could be expected from a set of Moderate and Advanced policies. This would result in an even larger reduction in electricity generation from the grid, because of the lower transmission and distribution losses in CHP systems. Assuming a 5% savings in line losses results in the following estimates of reduced grid electricity (Table E-5.4).

Table E-5.4 Electricity Generated by New CHP Systems

		Moderate		Advanced
	2010	2020	2010	2020
Cogenerated electricity above BAU (in TWh)	67.4	170.1	216.3	477.3
Inclusion of 5% credit for reduced line losses	70.8	178.6	227.1	501.2

The fuel displaced as a result of this reduced grid electricity depends upon the marginal electricity generation i.e., the electricity generation that would be shed because of the reduced demand. In the Moderate scenario, the marginal electricity is characterized by comparing the Moderate scenario with the sensitivity case that included the Moderate supply-side policies but not the Moderate demand-side policies. The energy consumed by the electric sector in the Moderate scenario is 2.5 quads less than the sensitivity case in 2010, and it is approximately 5 quads less in 2020. The principal fuels displaced are natural gas, coal, and renewables (Table E-5.5).

In the Advanced scenario, the marginal electricity is characterized by comparing the Advanced scenario with the sensitivity case that included the Advanced supply-side policies and the $50/tC domestic cap and trade program, but not the Advanced demand-side policies. The Advanced scenario consumed 2 quads less in 2010 and more than 5 quads less in 2020, relative to the sensitivity case. The principal fuels displaced are natural gas, coal, and renewables (particularly in 2020).

Table E-5.5 Type of Energy Displaced on the Grid

		Moderate		Advanced
TBtu/TWh Displaced on the Grid:	2010	2020	2010	2020
Coal	1.69	2.82	3.78	2.89
Natural Gas	4.07	2.66	3.36	3.07
Distillate	0.00	0.00	0.00	0.00
Residual	0.34	0.00	0.00	0.00
Nuclear	0.00	0.94	0.00	0.00
Renewable	3.05	2.35	1.26	3.43
Electricity Imports	0.00	0.00	0.00	0.00
Total	9.15	8.78	8.40	9.39

Multiplying these rates by the TWh of displaced electricity from Table E-5.4 results in the displaced energy shown in Table E-5.6. In the Moderate scenario, energy savings from reduced grid electricity ranges from 0.6 quads in 2010 to 1.6 quads in 2020. In the Advanced scenario the energy savings on the grid are even greater: 1.9 quads in 2010 and 4.7 quads in 2020.

Table E-5.6 Amount of Energy Displaced on the Grid

TBtus of Energy Displaced:	2010	Moderate 2020	2010	Advanced 2020
Coal	120	504	859	1447
Natural Gas	288	476	763	1538
Distillate	0	0	0	0
Residual	24	0	0	0
Nuclear	0	168	0	0
Renewable	216	420	286	1719
Electricity Imports	0	0	0	0
Total	648	1568	1909	4704

(2) The boiler fuel displaced in the industrial sector

The boiler fuel displaced in the industrial sector is estimated by multiplying each fuel s fraction of AEO99 projected 2010 industrial energy consumption (excluding motor gasoline, renewable energy, and electricity) by the estimated total fuel displaced. In both scenarios, the principal fuel that is displaced in the industrial sector is natural gas. The petroleum fuels that are displaced by CHP as boiler fuels include residual oil, distillate, and other petroleum fuels. Some coal is also displaced. The total amount of fuel displaced ranges from 0.3 quads in 2010 in the Moderate scenario to 2.1 quads in 2020 in the Advanced scenario.

Table E-5.7 Industrial Boiler Fuel Displaced by CHP Systems

Increment of Fuel Displaced by CHP Systems above BAU (Trillion Btu)	2010	Moderate 2020	2010	Advanced 2020
Natural Gas	191	640	543	1,629
Petroleum fuels:	46	112	111	243
Distillate Fuel	7	18	18	46
LPG	2	4	5	12
Petrochemical Feedstock	0	0	0	0
Residual Fuel	10	28	29	65
Other Petroleum	27	62	59	120
Coal:	40	121	89	225
Metallurgical Coal	0	0	0	0
Steam Coal	40	121	89	225
Total	277	873	743	2097

(3) The fuel used by the CHP units

The increment of natural gas and biomass used by the CHP systems (above the BAU forecast) is shown in Table E-5.8. Altogether these CHP fuels range from 0.6 quads in 2010 in the Moderate scenario to 4.4 quads in the Advanced scenario.

Table E-5.8 Fuel Used by New CHP Systems

Increment of fuel used by new CHP Systems above BAU case, in tBtu	2010	Moderate 2020	2010	Advanced 2020
Natural Gas	519	1,692	1,321	3,697
Biomass	108	299	258	736
Total Fuel Consumed (Trillion Btu)	627	1,991	1,579	4,434

The combined effect of these three types of energy impacts from new CHP systems is summarized in the following table. The result suggests that policies tackling barriers to CHP could reduce energy consumption by an additional 0.3 quads in the Moderate scenario in 2010 and by an additional 0.5 quads in 2020. The energy saved by new CHP systems in the Advanced case are estimated to be considerably larger: 1.1 quads in 2010 and 2.4 quads in 2020. The fuel mix of both the Moderate and Advanced scenarios would also be affected. Increased CHP would increase natural gas consumption, and decrease liquid petroleum gas, distillate, residual oil, and other petroleum-based industrial boiler fuels. It would also decrease coal in both the electricity and industrial sectors, and slow the growth of wind and biopower, especially in the Advanced scenario in 2020.

Table E-5.9 Total Energy Consumption Impacts of New CHP Systems

Total Energy Consumption Impact of CHP Systems, above BAU, in TBtu:	2010	Moderate 2020	2010	Advanced 2020
Coal	-160	-625	-948	-1672
Natural Gas	40	576	15	530
Petroleum (liquid petroleum gas, Distillate, Residual Oil)	-70	-112	-111	-243
Nuclear	0	-168	0	0
Renewable	-108	-121	-28	-983
Electricity Imports	0	0	0	0
Total	-298	-450	-1073	-2367

8. CARBON EMISSION REDUCTIONS

Carbon dioxide emissions reductions are estimated by using factors to convert the energy impacts shown in the above table into million tonnes of carbon (MtC). The conversion factors come from EIA s *Emissions of Greenhouse Gases in the United States* (1998, Table B1, p. 106). All of the petroleum-based fuel reductions are converted into carbon reductions by using the conversion factor for liquid petroleum gas, since it is the dominant petroleum fuel impacted by new CHP systems.

Table E-5.10 Factors for Converting Fossil Energy Savings into Carbon Emission Reductions

	Conversion Factors (MtC/TBtu)
Natural Gas	0.0145
Petroleum fuels:	
Distillate Fuel	0.0200
LPG	0.0170
Petrochemical Feedstock	0.0194
Residual Fuel	0.0215
Other Petroleum	0.0168
Coal:	
Metallurgical Coal	0.0255
Steam Coal	0.0257

The results suggest that policies tackling barriers to CHP in industry could decrease carbon emissions to well below BAU forecasts, in both scenarios. In the Moderate scenario they would reduce emissions by an additional 5 MtC in 2010 and 10 MtC in 2020, and in the Advanced scenario by an additional 26 MtC in 2010 and 40 MtC in 2020.

Table E-5.10 Total Carbon Dioxide Emission Reductions from New CHP Systems

		Moderate		Advanced
	2010	2020	2010	2020
(1) MtC Emissions Displaced at the utility	7.8	19.8	33.1	59.4
(2) The boiler fuel-generated MtC Displaced by the CHP systems	4.6	14.5	12.2	33.9
(3) The MtC produced by the fuel used by the CHP units	-7.5	-24.5	-19.2	-53.6
Total MtC Emissions Reductions	4.9	9.7	26.1	39.7

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