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Economic Potential of CHP In Detroit Edison Service Area: The Customer Perspective

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EXECUTIVE SUMMARY

DOE's mission under the Distributed Energy and Electricity Reliability (DEER) Program is to strengthen America's electric energy infrastructure and provide utilities and consumers with a greater array of energy-efficient technology choices for generating, transmitting, distributing, storing, and managing demand for electric power and thermal energy. DOE recognizes that distributed energy technologies can help accomplish this mission.

Distributed energy (DE) technologies have received much attention for the potential energy savings and electric power reliability assurances that may be achieved by their widespread adoption. Fueling the attention has been the desire to reduce greenhouse gas emissions and concern about easing power transmission and distribution system capacity limitations and congestion. However, these benefits may come at a cost to the electric utility companies in terms of lost revenue and other potential impacts on the distribution system. It is important to assess the costs and benefits of DE to consumers and distribution system companies.

DOE commissioned this study to assess the costs and benefits of DE technologies to consumers and to better understand the effect of DE on the grid. Current central power generation units vent more waste heat (energy) than the entire transportation sector consumes and this wasted thermal energy is projected to grow by 45% within the next 20 years[1]. Consumer investment in technologies that increase power generation efficiency is a key element of the DOE Energy Efficiency program. The program aims to increase overall cycle efficiency from 30% to 70% within 20 years as well.

DOE wants to determine the impact of DE in several small areas within cities across the U.S. Ann Arbor, Michigan, was chosen as the city for this case study. Ann Arbor has electric and gas rates that can substantially affect the market penetration of DE. This case study analysis was intended to:

1. Determine what DE market penetration can realistically be expected, based on consumer investment in combined heat and power systems (CHP) and the effect of utility applied demand response (DR).
2. Evaluate and quantify the impact on the distribution utility feeder from the perspective of customer ownership of the DE equipment.
3. Determine the distribution feeder limits and the impact DE may have on future growth.

For the case study, the Gas Technology Institute analyzed a single 16-megawatt grid feeder circuit in Ann Arbor, Michigan to determine whether there are economic incentives to use small distributed power generation systems that would offset the need to increase grid circuit capacity. Increasing circuit capacity would enable the circuit to meet consumer's energy demands at all times, but it would not improve the circuit's utilization factor.

The analysis spans 12 years, to a planning horizon of 2015. By 2015, the demand for power is expected to exceed the grid circuit capacity for a significant portion of the year. The analysis was to determine whether economically acceptable implementation of customer-owned DE systems would reduce the peak power demands enough to forestall the need to upgrade the

[1] *Annual Energy Outlook 2002 with Projections to 2020,* December 2001. Energy Information Administration, Office of Integrated Analysis and Forecasting, U.S. Department of Energy

capacity of the grid circuit. The analysis was based on economics and gave no financial credit for improved power reliability or mitigation of environmental impacts.

Before this study was completed, the utility expanded the capacity of the circuit to 22 MW. Although this expansion will enable the circuit to meet foreseeable increases in peak demand, it also will significantly decrease the circuit's overall utilization factor.

The study revealed that DE penetration on the selected feeder is not expected to forestall the need to upgrade the grid circuit capacity unless interconnection barriers are removed. Currently, a variety of technical, business practice, and regulatory barriers discourage DE interconnection in the US market[3].

Findings

Under a Business as usual approach, most industrial facilities in Ann Arbor without a recoverable fuel source will find it difficult to install DE and meet acceptable paybacks.

Improved Business Rules and Practices can improve DE penetration by as much as 50%.

Advanced Technology, which improves energy efficiency, reduces operation & maintenance costs and reduces installed costs, can further improve DE penetration by as much as 200%.

With Improved Business Rules and Technology, DE penetration can make an impact on utility feeders by displacing enough load to keep the demand below their respective capacity. This in turn can defer and possibly prevent the need for costly upgrades.

Demand Response is an effective method for reducing peak demand requirements on a utility feeder. However, it does not help displace significant load throughout the year.

DE reduces peak demand while displacing load, reducing emissions and saving fuel due to energy efficiency.

Additional building energy efficiency advances such as efficient lighting, solar photovoltaics, and advanced HVAC systems may further reduce the peak demands and provide greater power reserve margins.

[3] *Making Connections, Case Studies of Interconnection Barriers and their Impact on Distributed Power Projects.* July 2000, NREL report to U.S Department of Energy

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1.0 Introduction

1.1 Background

Distributed Energy (DE) is a term used to describe the generation of electric power near the point of use rather than at large central power plants. DE can include the on-site or near-site use of heat rejected by the generator's prime mover. Usually, DE is based on the use of natural gas fuels or renewable energy sources, such as solar energy, biomass, or waste. DE is increasingly being considered as a revolutionary technology with profound implications for consumers, distribution utilities, and government. These stakeholders are faced with different challenges and are influenced by various and sometimes conflicting motives, as shown in Fig. 1.1.

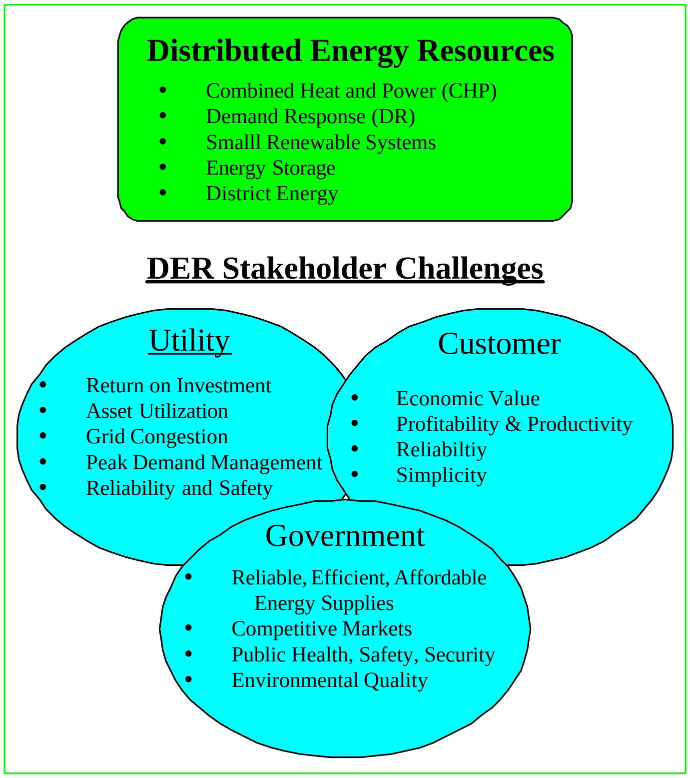

Figure 1-1 Distributed Energy Issues

A unique team of individuals from various organizations, including Gas Technology Institute (GTI), Energetics, Distributed Utility Associates (DUA) and the Department of Energy was assembled to study the economic potential for market penetration of DE. With Energetics providing project coordination, the customer and utility perspectives of DE where analyzed by GTI and DUA respectively. A single 16 MW commercial and light industrial feeder circuit in Ann Arbor, Michigan was selected for the case study. Although this region is not optimal for DE, due to its low power cost, it represents many territories in the U.S. where massive coal and nuclear power plants, built decades ago, dominate the electric supply. Other regions such as California, Chicago, and the Northeast could reflect economics that are more conducive to DE market penetration.

Many DE technologies are in use today, and more are being positioned to enter the market soon. Reciprocating engines and turbines, with their improving performance and decreasing installed cost, currently provide consumers with the least expensive and most reliable choices. Renewable energy sources, such as photovoltaic panels, wind turbines, and stored energy systems do not yet compete economically with engine systems in most applications. Fuel cells promise much lower emissions than traditional prime movers. However, they are not fully commercialized, and their relatively high cost currently limits them to niche markets where near-zero emissions or extraordinary power quality and reliability are required.

Currently, DE is predominantly installed to run on recoverable fuels in certain industries, including chemicals, paper, primary metals, and food. In this report, recoverable fuel is the term used to describe free, or almost free fuel derived from waste (such as biogas or refinery byproducts). There has been some penetration of natural-gas-fueled DE systems into commercial use, mainly driven by reliability issues. Current economics usually require DE projects to be justified by some additional purpose, such as reliability, use of waste heat, environmental factors, project co-funding, demonstration purposes, or municipal planning.

1.2 Current State of DE

Recently, DE technologies have received much attention for their potential to save energy and improve reliability. Fueling the attention has been the desire to reduce the U.S. reliance on fossil fuels, improve environmental conditions, and ease transmission and distribution congestion to avoid blackouts.

DE technology has been installed across the U.S. where a recoverable energy source exists, large steam and electric loads coexist, reliability is an issue, or electricity prices are high. More than 70% of industrial installed DE is in the chemical, pulp and paper and oil refining industries.[2] These industries all generate recoverable fuel byproducts. Table 1.1, below, summarizes the types of installed capacity of combined heat and power (CHP) by sector. From this table one can see that industrial facilities (with burnable waste fuels) have been at the forefront of DE installations. About half of the commercial sector capacity is found in colleges and district energy systems.[3] A more recent trend to DE installation has been occurring due to concerns about power security and quality. Organizations including hospitals, banks, and data centers have been installing DE systems in order to avoid costly economic losses or loss of life due to power outages.

Type	No. of Installations (1999)	Total CHP Capacity (1999)	Percent of Installed Capacity (1999)	Average Size	Median Size
Industrial	1016	45,465 MW	90%	45 MW	25 MW
Commercial	980	4,930 MW	10%	5.0 MW	0.7 MW
Total	1996	50,395 MW	100%		

Table 1.1 Estimated Installed CHP Capacity in the U.S. (1999) per U.S. EPA

While these DE systems are beneficial to end-users, utilities often claim that they may negatively impact the incumbent utility in terms of lost revenue and disruptions to the distribution system. Today, much of the U.S. enjoys relatively low electricity prices due to nuclear (22% of national total) and coal (55%) fuels that generate electricity for less than 2 cents/kWh per the EIA 2002 Energy Outlook[4]. Generating peak power at large utilities however has a higher distribution cost due to generation dispatching, lower utilization factors, lower efficiencies and higher cost of fuels. In regions such as the Northeast and California, significant use of simple cycle gas turbines results in higher electricity costs. In addition to generation cost, the cost of distribution can add

[2] *The Market and Technical Potential for Combined Heat and Power in the Industrial Sector*, January 2000, OSEC report to Energy Information Administration, U.S. Department of Energy
[3] *The Market and Technical Potential for Combined Heat and Power in the Commercial/Institutional Sector (Rev. 1)*, January 2000, OSEC report to Energy Information Administration, U.S. Department of Energy
[4] *Annual Energy Outlook 2002 with Projections to 2020,* December 2001. Energy Information Administration, Office of Integrated Analysis and Forecasting, U.S. Department of Energy

significantly to the amount customers pay for power, especially during peak periods. Large cities with expansive and costly distribution networks such as Chicago, have relatively high peak electricity prices.

1.3 The Future of DE

One vision for distributed energy includes reshaping the way that consumers generate, distribute, and use electricity to improve grid utilization; avoid capital expenses for grid capacity upgrades; and improve energy efficiency. Utilities would identify distribution system constraints and direct private investment via economic incentives while identifying potential end-user sites for utility operation and installation of DE technology. Customers would have choices to install 70%+ efficient, highly reliable lower cost systems on-site that provide for the recovery and use of thermal energy locally. Another vision is a future where many distribution circuits would have 10 or more DE systems, which would provide diversity of supply, thereby reducing DE backup requirements to 10% to 20% of the total DE capacity. Utilities would establish nationwide standard criteria for interconnection and reliability. DE systems would be in communication with the grid and could be called upon to provide additional capacity when necessary. In cases where DE is installed on a network feeder, DE systems would include the necessary protective relaying for safe and effective interconnection.

2.0 ASSESSMENT METHODOLOGY

2.1 Purpose

This study is a customer perspective on the feasibility of DE penetration with respect to consumer savings, reliability, and the removal of installation barriers on a specific feeder circuit in an actual electric grid. The approach, based on a long list of defensible assumptions (See Appendix 1), was threefold:

1. Model a real community with existing customers and potential new customers.
2. Perform economic analyses on various customers that show business cases and potential benefits.
3. Evaluate the findings and determine realistic DE penetrations and the impact on the electric grid.

Though the methods employed in the study can be applied to any area in the U.S., a 16 MW peak load capacity circuit on the Pioneer substation located in Detroit Edison's (DTE Energy Company) service territory was selected as a case study. By looking at a particular feeder, the actual demand load, customer building types, and cost of capacity upgrades are considered and real DE penetrations can be predicted. Because large coal and nuclear central plants supply much of DTE's power, the energy component of the electricity price is fairly low. Therefore, economics for DE projects that do not use recoverable fuel or are not reliability/security driven were initially expected to be poor. Other areas of the country will have different results – with improved DE economics in higher power cost areas such as the Northeast, California, and Chicago and degraded DE economics in lower power cost areas such as many of the Southern and Western states (e.g. MN, WA and states encompassed by TVA).

2.2 Circuit Description

DTE and Ann Arbor village planning officials provided a tour of the area. The Pioneer substation was chosen as the focus of analysis because it represents a good range of industrial and commercial facilities and the area is subject to a great deal of expansion. The 16 MW circuit feeds 1/3 commercial and 2/3 light industrial customers with plans for significant growth. The area consists mostly of industrial parks with offices and industries. Most important is the open land slated for new customers, including more industrial parks. Based upon discussions with DTE officials, load growth is predicted to be 4%/year for the next five years then 3%/year for the following 5 years and 2%/year after that. However, DTE has placed a physical limit of 25% customer-installed DE on the circuit. The fundamental approach taken for this study with regard to load growth was that new customers on the feeder would be similar to existing customers. Buildings that are not typical on the feeder (e.g. hospitals) were analyzed in this study, but not considered to be future customers on the feeder.

2.3 Assumptions

An economic assessment, represented by a life-cycle cost and associated payback period, was assumed to be the basis for all customer decisions. Payback times were not calculated based on "simple payback". They are based on the life cycle cost analysis and are calculated considering depreciation, interest rates, cost of capital, income tax, and inflation, per the assumptions. Favorable economic thresholds were defined for the purpose of this analysis as less than ten years for institutional and government facilities and less than five years for private sector facilities. Actual penetration would increase as payback times decrease.

The analysis was based upon the extensive list of assumptions shown in Appendix 1. It is important to note that this study was economically conservative in all aspects of the analysis. For example:

- The feeder chosen is in a region that is not favorable to DE economics because of low electric utility rates.
- Economic models included the cost of capital, which adds 1 to 3 years to simple payback models.
- Fuel rates and equipment O&M escalated 2% per year.
- DE reliability (downtime) was accounted for as described in section 2.6.

The Business as Usual (BAU) scenario assumes that current rates, market structure, and technology are maintained until 2015.

The Improved Business Rules (IBR) scenario assumes that business practice, and regulatory DE barriers are removed and the value of DE to assist in maintaining the grid, avoiding blackouts and serving critical power loads is properly assessed. Based on the DOE's "Making Connections" report, capital costs are reduced by 10% for streamlined interconnection, siting and engineering.[5] New construction without the complications accompanied by retrofit work avoid additional costs associated with interconnection, siting and engineering. Capital cost for new construction is reduced by an additional 20% below the previously reduced (10%) capital cost for a total of 30%.

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[5] *Making Connections, Case Studies of Interconnection Barriers and their Impact on Distributed Power Projects*. July 2000, NREL report to U.S Department of Energy

The Improved Business Rules and Technologies (IBR&T) scenario uses the same assumptions as the IBR scenario with the addition of technological advances in DE equipment, installation, efficiency, and operation. Based on DOE studies prepared by Energy Nexus Group[6], efficiencies will improve by 15% to 25% and O&M costs will decrease by 10% to 20% depending on size (reference the Technical Assumptions in Appendix 1). Capital costs will decrease by 13% for applications greater than 500 kW and 20% for applications less than 500 kW for a total of 23% to 50% reduction depending on application size and new or retrofit construction.

2.4 Rate Structures

The utility rate structures were key elements of this analysis. Various electricity rates were analyzed, but all were based on two fundamental DTE rate structure configurations. Thorough study of DTE's rate sheets and extensive conversations with DTE officials were the basis for understanding and applying the rates to the specific feeder chosen. These rates were characterized by low energy charges and demand charges and standby rates that were comparable to many other Midwestern utilities. These rate structures do not favor DE, because DE operating cost is based upon natural gas prices while the electrical energy prices charged by DTE are based on less expensive coal and nuclear fuels. Central station coal and nuclear power costs can be 50% lower than comparable natural gas-fired central generation costs. Given such low energy rates, it costs more to run DE than to buy power from the grid during off-peak hours when no demand charges apply. For this reason, the analyses were based only on on-peak DE run times. DTE rate sheets can be found at the following web site:

http://utilities.dteenergy.com/infoZone/publications/electricRateBook.html

2.4.1 Natural Gas Rates

Natural gas rates were set using the current natural gas price of $5.00/MMBtu. As stated above, gas prices were assumed to escalate at a rate of 2%/year for the span of the study.

2.4.2 DTE Power Rates

The two fundamental rate structures used in this study are for primary grid supply service and parallel operation.

DTE's Primary Supply Rate (designated D6) is a typical rate for commercial and light industrial customers in the territory. It has an on-peak and off-peak energy charge accompanied by various surcharges, all billed per kWh. The on-peak hours are 11:00 a.m. to 7:00 p.m. weekdays, excluding legal holidays. There is a typical monthly demand charge billed per kW in the respective month. There is also a maximum demand charge, which is billed per maximum kW across a rolling 12-month period. Finally, there is a small monthly service charge. The D6 rate is available to customers desiring service at any voltage level. However, the maximum demand charge is stepped up as the voltage requirement is decreased. See Appendix 2 for more details.

DTE's Parallel Operation and Standby Service (designated Standard Contract Rider #3) is a rate typical to commercial and light industrial customers in the territory who intend to have on-site generation in parallel with the grid. The components of the rate structure are similar to D6. The energy and surcharges are the same and the service charge is almost the same. However, the

[6] *Reciprocating Engine Technology Characterization - Peer Review Draft*, November 2002. Report for NREL, Energy and Environmental Analysis, Energy Nexus Group

demand charges differ in that they are billed per kW per day of standby and maintenance demand. Maintenance days are pre-scheduled DE outages, which were avoided in this study, as maintenance would be done during off-peak hours. Rider #3 has two additional charges billed per kW – Generator Reserve Fee and Standby Charge.

2.4.3 Nationwide Rates

In order to determine how the results of the study would vary for other rates, more typical of those found across the nation, two cents were added to the on- and off-peak energy charges. All other charges remained the same during this analysis. This analysis is also relevant to the DTE region because discussions with DTE personnel concluded that it is reasonable to expect a 2-cent-per-kWh increase in energy rates in DTE territory during this study's time span. Several factors suggest upward pressure on utility rates, including:

- Impacts of environmental policies on fossil generating costs to reduce NOx, SOx, CO2, Heavy Metals, and CO.
- Minimum renewable energy portfolio standards.
- Increased natural gas base-load and peak-load generation.

2.5 Building Models

The following existing buildings were analyzed with various DE arrangements, based on the tour of the feeder:

- School
- Newspaper Press
- Light Industrial
- Low-Rise Office
- Data Center

School

Newspaper Press

Low-Rise Office

Light Industry

Data Center

In addition to the existing building types, many new building types were analyzed for each of the scenarios[7]. Customer annual energy consumptions along with annual bills were not available. Therefore, typical CHP profiles were generated, based on building types and approximate load information provided by DTE. Economic analyses were run for commercially available generator sizes and corresponding installed costs until payback times were minimized. When absorption chillers are added to a CHP application, it is termed Combined Heating and Power with Cooling (CHP/C). For applications where the payback times for CHP reached the threshold for private investment, absorption chillers were added and CHP/C analyses were performed. Recoverable heat-driven cooling equipment was also optimized to obtain the shortest payback times. Generally CHP/C improves energy efficiency year-around, but it adds up to one year to the payback times relative to heating and power alone because of additional capital costs. The impact of CHP/C could be very different in a southern climate where cooling loads are greater.

2.6 Distributed Generation Technology

Each of the building types were configured for internal combustion engine power generation with heat recovered for space heating, domestic hot water, desiccant dehumidification, and single-effect absorption chillers (only CHP/C analyses were run with absorption chillers). The buildings were also configured for constant-volume air-handling chilled-water systems using electric screw chillers and steam fired single-effect absorption chillers. The systems were configured with gas-fired desiccant dehumidification systems and sensible heat exchangers to recover heat from the air exhausted from the building for ventilation purposes. Economizers were not used.

DE reliability was given two levels of monetary value at $45/kW and $180/kW. Customers with critical loads (e.g. hospitals, data centers,

[7] *Building Energy Analyzer, Version 1.3 Implementing DOE21.E Computational Engine Based Modeling*, December 2001. Gas Technology Institute Modeling Software

etc.) must have full, long-term backup power with independent fuel systems. $180/kW was used to displace backup diesel fired generation cost. Customers with loads that are not critical would still require some level of backup power. $45/kW was used to displace Uninterruptible Power Supply (UPS) systems cost. Only customers constructing new buildings were given these credits, because existing buildings would already have the backup systems in place.

DE outages were also accounted for. The DTE Parallel Operation rate structure has a daily on-peak demand charge of .90$/kW/day in addition to the annual peak demand charge. This charge was applied to the standby charge based on 95%, 96%, and 99% reliable technology for Business as Usual, Improved Business Rules, and Improved Business Rules and Technologies, respectively.

For example, the 95% Business as Usual case would be calculated as follows:

(2080 hrs/yr) x (100%-95%) = (104 hrs/yr) x (1 day/8hrs) = (13 days/yr) x ($0.90/kW/day) =

($11.7/kW/yr) x (1 yr/12 mo) = $0.975/kW/mo.

This was rounded to $1.00/kW/mo and added to the current standby charge.

Based on the tour and economic analyses of the buildings, the composition of the load served by the model feeder was developed and is summarized in Table 2.6, below. The study analyzed the feeder in 2003 and again in 2015, assuming the new buildings would have been added to the feeder.

Model Feeder			
	2003 Bldgs	2015 New Bldgs	2015 Bldgs
Low Rise Office	9	6	15
Data Center	1	1	2
School	2	0	2
Light Industrial	4	1	5
L Ind w/ recoverable	1	1	2
Total	17	9	26

Table 2.6 Feeder Load Compositions

2.7 Feeder Load Duration Curves

Hourly demand data, in the form of load duration curves, are typically used to assist in the analysis of electricity demand. These curves were used to clearly define the demand peaks on the feeder with respect to the durations that the demands are present. The curves were used to compare the effects of Demand Response and CHP applications on the feeder.

3.0 RESULTS

3.1 DTE Rate Schedule

For each scenario, an analysis for each building was done to compare the potential economic benefits of on-site power generation and thermal heat recovery (Alternative Technology) to buying power from the utility grid (Baseline Technology). As stated in the assumptions in Appendix 1, net metering was not considered. The annual monetary savings of the Alternative Technology over the Baseline technology determined the payback period.

The outcome of the customer-perspective payback times is shown in Table 3.1. To acquire a broader perspective of the economics, buildings that may not necessarily be built on the feeder were also analyzed (e.g. high rise office, hospital, heavy industrial).

Paybacks in Years by Scenario & Building Type Under DTE Rate Structure					
Buildings w/ IC Engine CHP Gensets	**BAU**	**IBR**	**IBRT**	**Peak Dmd**	**On-Site kW**
Existing School	8	7	3	1376	550
Existing School w/ Abs. Chillers	8	5	3	1376	550
Existing Newspaper Press	12	11	7	970	550
Existing Newspaper Press w/ Abs. Chillers	13	12	8	970	550
Existing Low-Rise Office	25	21	12	205	190
Existing Light Industry *	5	3	2	970	550
Existing Light Industry w/ Abs. Chillers*	7	5	3	970	550
Existing Data Center	11	10	6	3609	2000
Existing Data Center w/ Abs. Chillers	11	10	6	3609	2000
New School	8	4	2	1376	550
New School w/ Abs. Chillers	8	5	3	1376	550
New Newspaper Press	12	9	4	970	550
New Newspaper Press w/ Abs. Chillers	12	10	6	970	550
New Low-Rise Office	24	18	11	205	190
New Light Industrial *	4	2	2	970	550
New Light Industrial w/ Abs. Chillers*	6	3	2	970	550
New Heavy Industrial *	2	1	1	5002	2000
New Heavy Industrial w/ Abs. Chillers*	2	1	1	5002	2000
New High-Rise Office	12	9	4	985	550
New High-Rise Office w/ Abs. Chillers	12	9	5	985	550
New Hospital	8	4	2	2540	2000
New Hospital w/ Abs. Chillers	8	4	2	2540	2000
New Data Center	9	7	2	3609	2000
New Data Center w/ Abs. Chillers	9	8	2	3609	2000
Buildings w/ Fuel Cell CHP Gensets	**BAU**	**IBR**	**IBRT**	**Peak Dmd**	**On-Site kW**
New School	NP	NP	9	1376	750
New School	NP	NP	8	1376	500
New School	NP	NP	10	1376	500
New School	NP	NP	9	1376	500
New Heavy Industry *	NP	NP	3	5002	2000
New Heavy Industry w/ Abs. Chillers **	NP	NP	5	5002	2000
New Heavy Industry w/ Abs. Chillers *	NP	NP	9	5002	2000
Buildings w/ Gas Turbine CHP Gensets	**BAU**	**IBR**	**IBRT**	**Peak Dmd**	**On-Site kW**
New Hospital w/ Abs. Chillers	NP	NP	5	2540	2000

Table 3.1 Payback Times for Buildings on Model Feeder, Based on Current DTE Rates

* All Heavy and Light industries are assumed to have 25% recoverable fuel.
** Heavy Industry with 50% recoverable fuel.
NP = Negative Payback. Customer would never recover investment.

From the economic analyses and payback findings above, the following outcomes were observed:

- As expected, capital cost is the key factor in decreasing the payback time and increasing penetration.
- Engine technology reflects shortest payback times among the prime movers, because they have the lowest installed cost.
- DTE's low electric energy costs (2 cents/kWh) are a major factor in diminishing the economic benefits of DE in DTE's territory.
- DE economies are driven by demand charges, which apply only from 11:00 a.m. to 7:00 p.m., or 2080 hours per year. This effectively limits the operating hours of DE systems to 2080 hours per year because the DE system operating costs are greater than the alternative cost of purchasing electricity and heat during the remaining 6690 hours per year. Most buildings have high-demand periods longer than 8 hours, however; and, while a CHP system will reduce loads during much of the building's peak period demand, the high building demand that occurs just before the CHP system turns on must be met by the grid. Therefore, although CHP would reduce much of the peak demand on the feeder, unmet shoulder demand will still limit the effectiveness of CHP in reducing the power load on the grid.
- The cost of the additional equipment necessary to recover thermal energy for cooling added up to one year to the payback times. For this reason, CHP/C analyses were done only for applications that were first successful without absorption chillers.

3.2 Scenario Analyses

To determine which customers on the feeder might consider DE, life-cycle payback times were calculated for each scenario. Payback times of five years or less are considered to represent sound investments. However, because schools are considered to be institutional, their payback time threshold was set at ten years.

3.2.1 Business as Usual (BAU)

Current capital costs to install reciprocating-engine-based DE are listed in the assumptions in Appendix 1. Based on these capital costs, the buildings were modeled and the economics determined. Figure 3.2.1.1, shows life-cycle payback times for the individual building types sorted (left to right) by decreasing potential to penetrate the market.

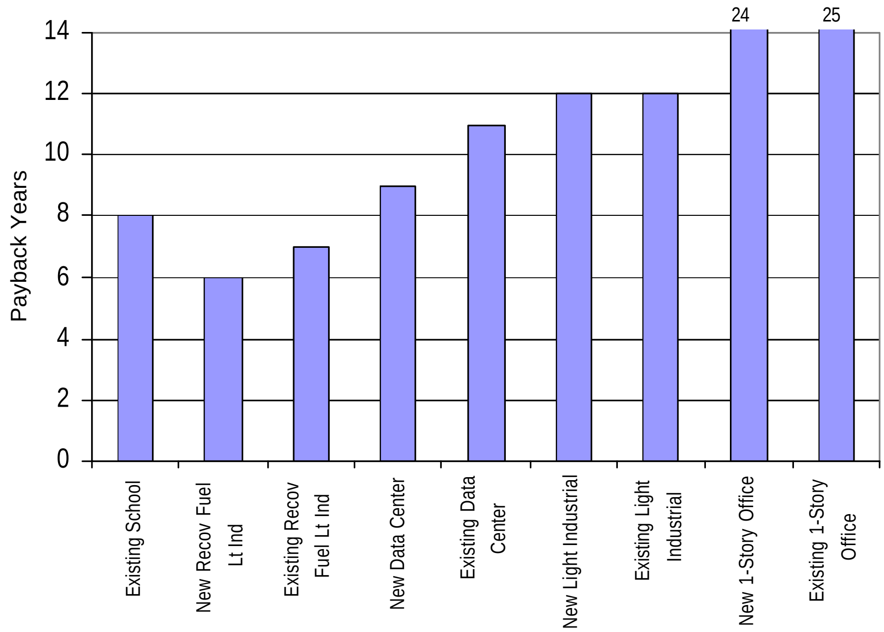


Figure 3.2.1.1 Paybacks by Building Type
Business as Usual Case

- Under the Business as Usual scenario, DE economics are favorable for CHP in schools (schools and other institutions are assumed to accept payback times up to 10 years). This evaluation reflects recent reciprocating engine advances that reduced costs by 30%.
- Low energy costs (2 cents/kWh) are a major factor in limiting favorable DE/CHP economics under the Business as Usual scenario in DTE's territory. In addition, DTE’s demand charges apply during peak periods from 11a.m. to 7 p.m., or 2080 hours per year. This limits the fraction of the time that CHP systems can compete with power from the grid. It correspondingly limits the fuel savings and emissions reductions offered by CHP. CHP offers the greatest energy efficiency benefits when operated as a base-load technology.
- Light Industrial customers with recoverable energy will consider DE. Additional examples of recoverable energy include excess steam at a paper mill, landfill or municipal water treatment waste gases, and industrial waste gases, such as volatile organic chemicals.
- It was assumed a heavy industrial customer (2 MW) would not build on this feeder circuit. However, this application was analyzed in addition to those shown above and was found to have a 2-year payback time.

Figure 3.2.1.2 shows the installed cost of DE that would be needed to achieve the applicable payback time criteria (the lower portion of the bars) and compares these costs to the current installed costs (full length of the bars). The graph shows, that the data center and light industry buildings require installed costs of DER of $400-$600/kW to make ventures economical in the Business as Usual scenario. This also holds true for building types not shown in this figure, including new newspaper presses, hospitals, and high-rise office buildings if they were built on this feeder. Schools, with their tendency for high heating requirements and longer acceptable payback times, can justify DE costing $1600-$1700/kW. Light industries can install DE economically for high costs as well (up to $1000/kW), if recoverable fuel is available. Interestingly, these findings are confirmed by current practice. Installed costs today range from $800/kW to $1500/kW, and, as previously mentioned, industries with recoverable fuel have been using DE for many years. Additionally, on the commercial side, colleges have installed significant DE capacity across the nation. One-Story office buildings have higher actual installed costs because their loads are smaller, which puts them in the higher $/kW bracket. Also, 1-story office buildings were assumed to have UPS systems for backup power and thus were given $45/kW reliability credit rather than $180/kW. Installed costs required to achieve acceptable payback for 1-story office buildings are very low because energy cost savings are minimal.

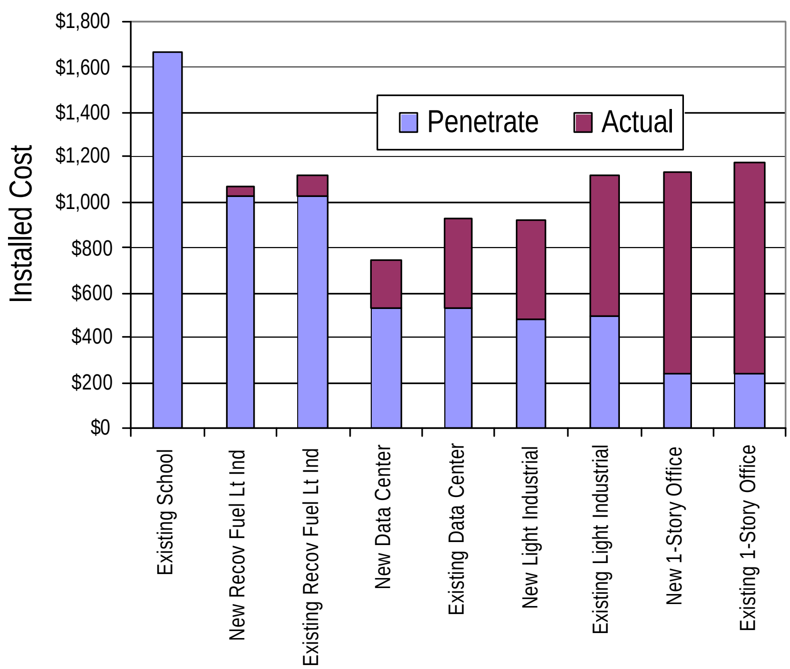


Figure 3.2.1.2 Installed Cost vs. Installed Cost Required to Achieve Acceptable Payback Business as Usual

3.2.2 Improved Business Rules (IBR)

Life-cycle payback times for the individual buildings were calculated for the Improved Business Rules scenario and charted alongside the previous results for Business as Usual scenario in Figure 3.2.2.1. The graph shows the improvements in payback times that would be enabled by improved business rules.

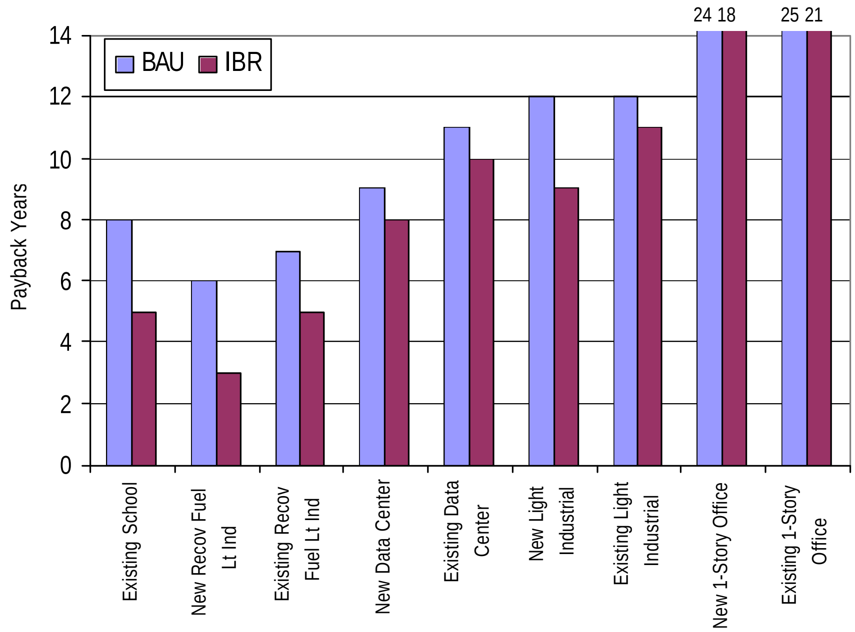


Figure 3.2.2.1 Paybacks by Building Type
Improved Business Rules

- Lower installation costs attributable to easier siting and permitting improve the payback times in all cases, relative to the business as usual cases.
- In addition to the schools, new and existing light industries that can take advantage of recoverable fuel (i.e. 25% recoverable fuel) could enter the DE market under improved business rules.
- Although they may not build on this feeder, new government office buildings, hospitals, and large industries were evaluated and found to have favorable DE economics in this scenario. Existing large industries would also see favorable DE economics.
- Customers who cannot tolerate extended outages may consider installing DE. For example, data centers may install DE even though the eight-year payback time would not meet the assumed investment criteria. Hospitals may also consider DE for similar reasons.
- Project co-funding or municipal energy planning may motivate some customers to install DE.

Figure 3.2.2.2 indicates that with the Improved Business Rules scenario, the installed costs needed to achieve the applicable payback time criteria remain between $400 and $600/kW. However, because the actual installed costs are lower under this scenario, payback times are lower. New construction of facilities with larger energy loads would begin to enter the DE market under this scenario, due to the reduced cost barriers. Likewise, facilities with critical energy loads that were previously considering DE may also begin to enter the market if the added value of critical service and reliability were considered in the economics.

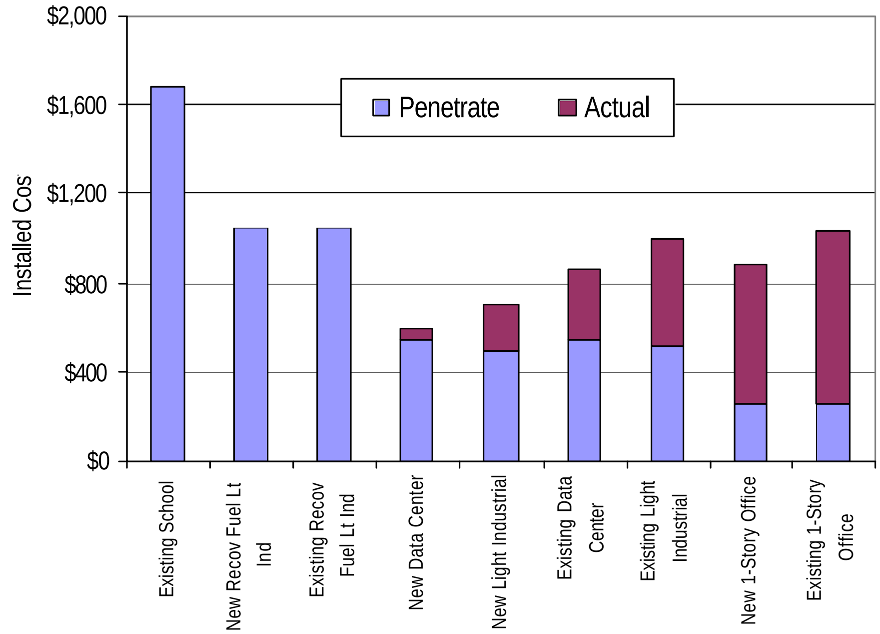


Figure 3.2.2.2 Installed Cost Required to Achieve Acceptable Payback Improved Business Rules

3.2.3 Improved Business Rules and Technology (IBR&T)

Per the technology assumptions in Appendix 1, due to advances in DE technologies, including greater efficiencies, lower installation costs, and greater sales volumes, total costs for DE systems will be lower under this scenario. The analysis showed that these advanced technologies would have great impact on the payback times, as shown in Figure 3.2.3.1.

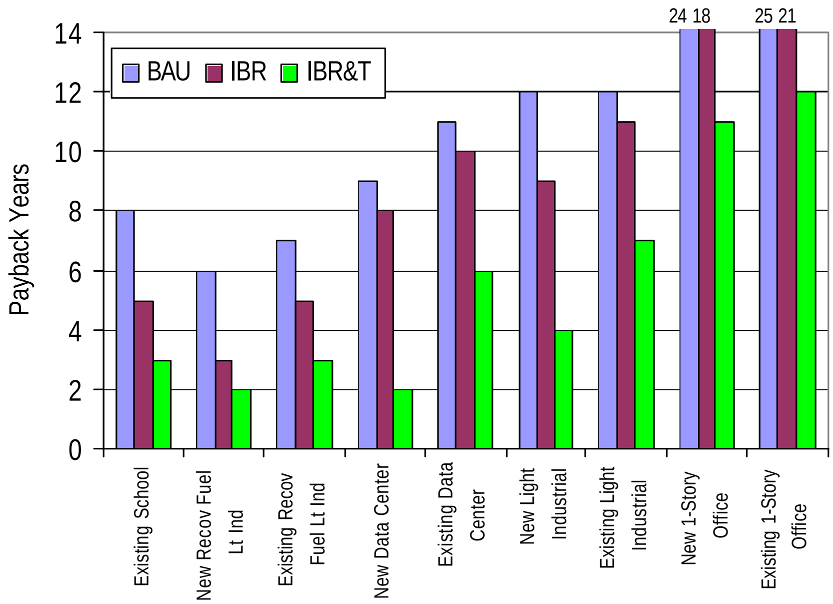


Figure 3.2.3.1 Paybacks by Building Type Improved Business Rules and Technology

- Under the Improved Business and Advanced Technology scenario, penetration on this feeder is expected to be able to reach over 30%, saving the customers almost $1,000,000 per year.
- Lower costs and higher efficiencies from successful Research, Development, and Deployment would improve payback times dramatically by 5 to 7 years.
- Use of DE in existing schools, existing and new recoverable-energy light industrial buildings, new data centers, and new light industrial buildings would become economically attractive.
- With the reduced capital costs, all new construction building types, except 1-story offices, in this study showed payback times less than five years.
- New buildings that may not be built on this feeder, including hospital, high-rise, heavy industrial, and newspaper press, were also evaluated and showed payback times less than 5 years.
- Existing buildings (e.g. data center and newspaper press) are only slightly beyond the five-year payback mark.
- Penetration would exceed the 25% physical limit on customer-installed DE on the circuit estimated by DTE.

The primary differences between the Improved Business Rules and Improved Business Rules and Technology scenarios are that the latter has higher efficiencies and 13-20% lower installed costs. As Figure 3.2.3.2 indicates, the technological improvements would make most DE projects economical with installed costs of $600-$800/kW. Not shown are the hospital and high-rise office, which also would be economical at $600-$800/kW.

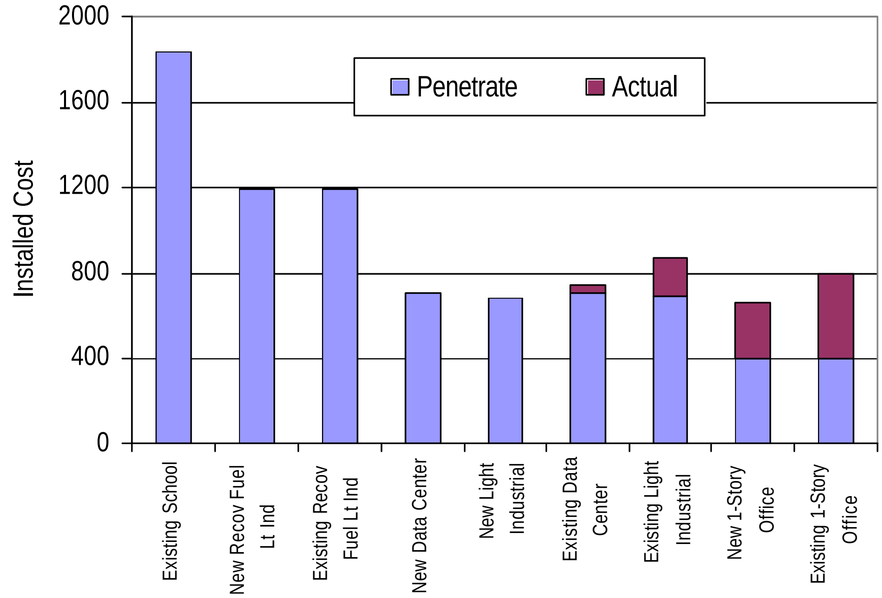


Figure 3.2.3.2 Installed Cost Required to Achieve Acceptable Payback Improved Business Rules and Technology

Figure 3.2.3.3 reflects advanced technologies other than engines. A gas turbine installed at a new hospital would become a very viable DE option. A fuel cell that could meet the assumed advanced technology installed cost and performance targets would approach the benchmark price point, particularly if recovered fuel were available. As with previous cases, 25% and 50% recovered fuel scenarios were used. However, applications with lower heating and cooling loads relative to their power loads (i.e. low-rise office) are not good candidates for DE, even under the Improved Business Rules and Technology scenario. It is clear that applications that can take advantage of energy efficiency are the most likely to install DE.

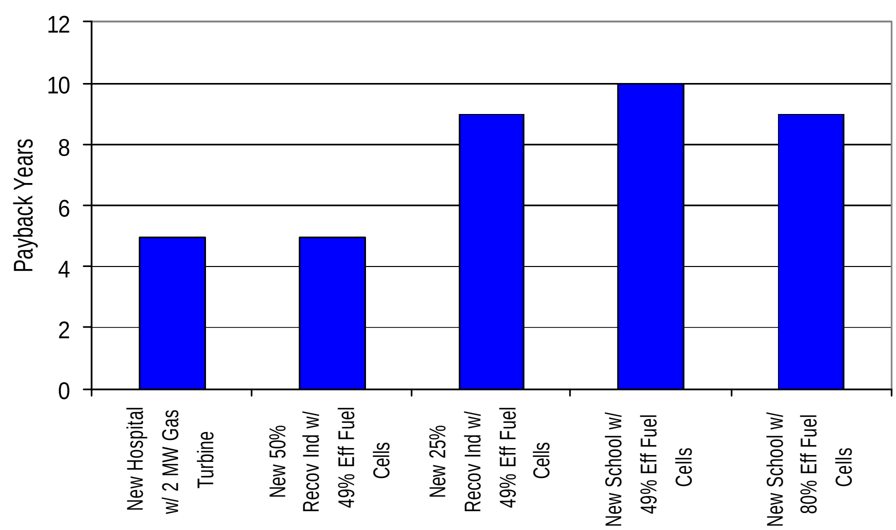


Figure 3.2.3.3 Alternative CHP Prime Movers Improved Business and Technology Scenarios

3.3 CHP Penetration

Maximum DE penetration for the model feeder, determined for 2015, is shown in Figure 3.3. For example, if DE projects result in 4-year payback times in the Business as Usual scenario, roughly 1000 kW of total DE will be installed on the feeder.

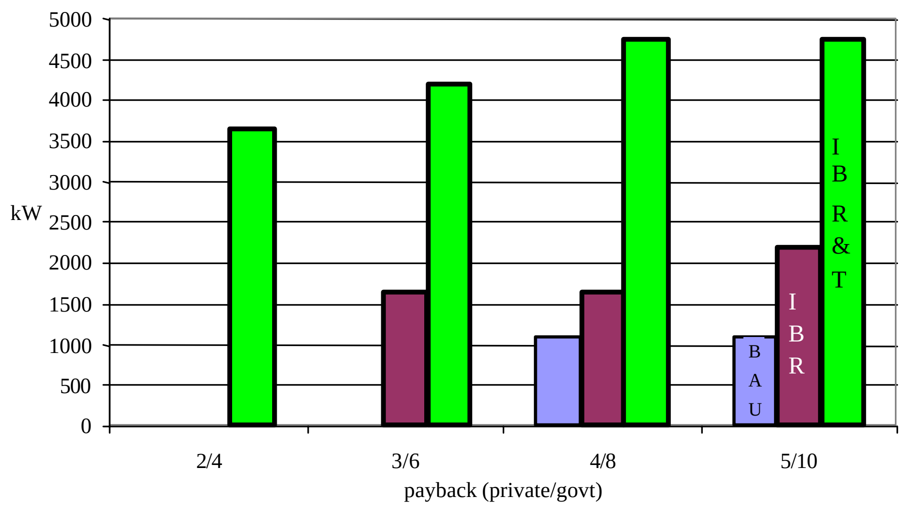


Figure 3.3 Maximum Potential Penetration of DER

Three key variables affect the economics of CHP and contribute to improved penetration across the scenarios.

- Reduced technology costs and improved performance can reduce payback times by 5-7 years, with advances expanding the market into commercial buildings.
- Barrier removal (leading to reductions in installation cost) reduces payback times by 1 to 4 years.
- Utility rates significantly affect DE economics. For example, eliminating standby charges would reduce payback times by 2 to 4 years.

3.4 Feeder Circuit Load Displacement

In addition to providing peak-load relief on the feeder, DE is clearly capable of providing energy efficiency and environmental benefits. Figure 3.4, reflects the results of implementing DE within the buildings on the model feeder. In the Advanced Technology Case (ATC), enough fuel would be saved to provide energy for two new schools.

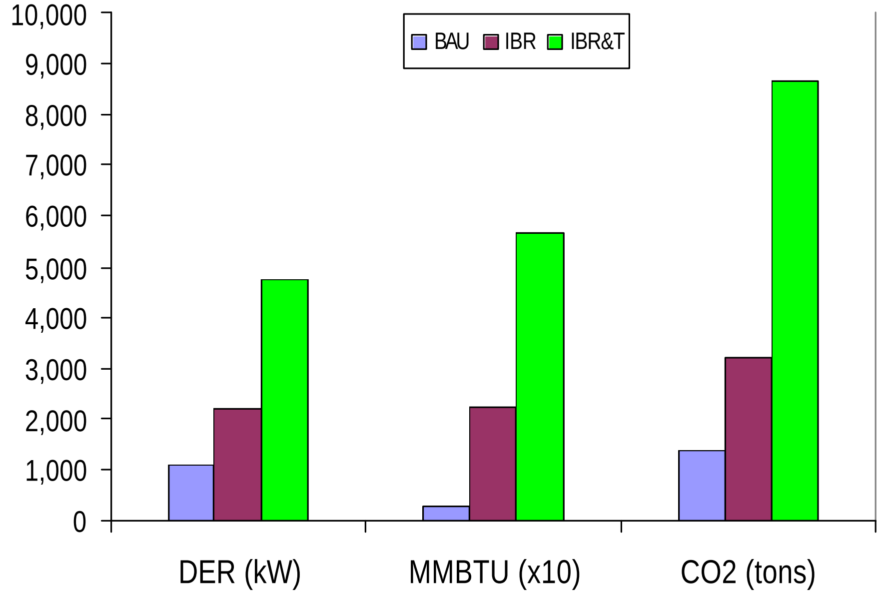


Figure 3.4 Model Feeder kW Installed and Annual MMBTU & CO2 Saved (2000 hours on DTE Rates)

3.5 Feeder Circuit Load Duration Curves

Load duration curves, were prepared based on the hour-by-hour building data streams generated by Building Energy Analyzer. The streams were aggregated to form a complete feeder curve.

3.5.1 CHP Load Duration Curves

Figure 3.5.1 shows synthesized load duration curves for the modeled feeder circuit, based upon the sum of the hourly loads for the individually synthesized building load curves. The load duration curve shows the demand for each hour of the year. This hourly demand is sorted to clearly show the peak demand and overall grid utilization. Because they were synthesized, these curves do not account for severe seasonal variations, which would generate exceptional demand spikes.

CHP, as defined on the curve, is DE used to reduce the overall demand across a one-year span and maximize energy efficiency, based on the market penetration attractive to customers.

DR (demand response), as defined on the curve, is DE used to reduce peak demand on the grid (i.e. DR controlled by the utility and used to defer grid capacity upgrades).

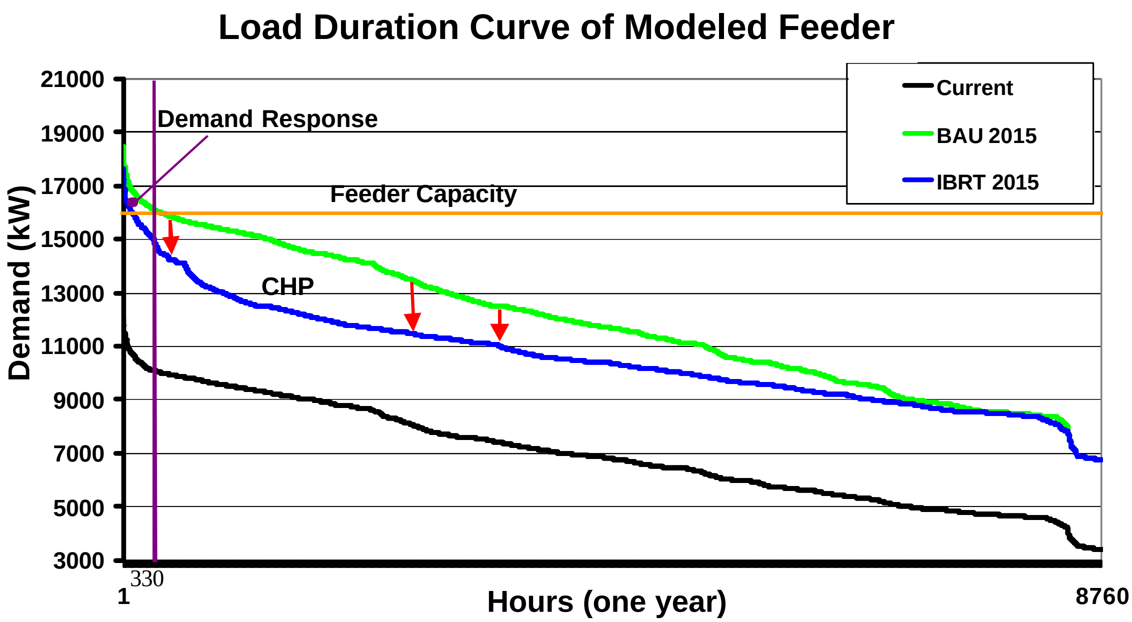


Figure 3.5.1 Load Duration Curve of Modeled Feeder

The feeder circuit capacity is 16 MW. Under the Business as Usual scenario the peak demand will be 18.5 MW, which means that a circuit capacity upgrade of at least 2.5 MW would be required before 2015. The installation of economically justified CHP would absorb considerable load but the peak load would still be too high at 17.6 MW, and a feeder capacity upgrade would still be needed. The following results were obtained:

- DR would require roughly 330 hours per year to clip peak demands by 2.5 MW, which would bring the 18.5 MW down to 16 MW.
- CHP reduces the 18.5 MW by about 0.6 MW. However, CHP also displaces a great deal of load throughout the span of the year and significantly reduces the need for DR.
- CHP along with roughly 80 hours as opposed to 330 hours per year of DR would keep the feeder under 16 MW, with significant energy efficiency gained.

3.5.2 Load Management

Further analysis suggests that sufficient load management could be achieved by extending on-peak hrs (EH) or applying energy efficient technology (EE) and solar photovoltaics (PV). Figure 3.5.2 shows load curves that were generated to reflect the results of load management. EE includes energy efficient lighting and advanced HVAC equipment. Economics associated with EH, EE and PV were not determined in this study.

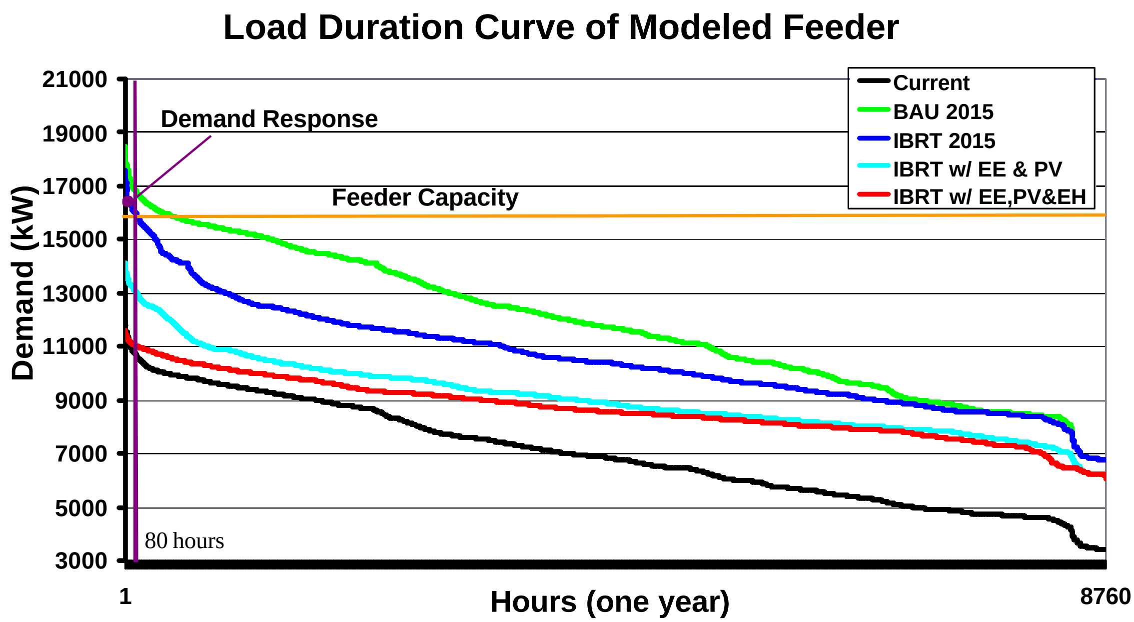


Figure 3.5.2 Load Duration Curve of Model Feeder with EE, PV and EH

The graph shows that implementing energy-efficient technology, along with solar photovoltaics, will again reduce both average and peak demand on the feeder. Extending the on-peak period from 11 a.m. - 7 p.m. to 11 a.m. to 9 p.m. and assuming that the DE units will then be run during that period reduces the average and peak demand further. The following results were obtained:

- Additional building energy efficiency advances, such as lighting, solar photovoltaics, and advanced HVAC systems may further reduce the peak load.
- Extending the on-peak period may further reduce the peak load.
- Reducing the standby charge for selected customers would be a sufficient price signal for customers to add DR or CHP.
- With CHP and DR, distribution system costs fall, system stability could be improved, and grid capacity expansions are deferred. This may lead to public utility commissions setting lower demand charges.

3.6 More Typical Rate Schedules

DTE is similar to many utilities in the United States, whose off-peak electric costs to consumers are around 2 cents/kWh. In their territories, gas-fired CHP cannot compete with coal- or nuclear-based power prices and is not economical to consumers. However, during on-peak periods, large demand charges often improve DE economics and consumers can use DE to avoid demand charges. Most utilities, including DTE, impose demand charges for a whole month or even longer for any DE outages, and these charges can render DE uneconomical. With current business rules and technologies, DE is economical only where a recoverable energy source is available or power reliability is a concern.

High-cost electric markets in the Northeast, California, Chicago, and Texas provide opportunities for much higher DE penetration rates. These high-cost markets are in general the result of heavy reliance on higher cost simple cycle gas and oil generation combined with large metropolitan areas that have higher distribution costs.

This conclusion is consistent with the minimal penetration by CHP within DTE's territory, totaling only 191 Megawatts to date (2%). This analysis suggests that DE might expand its role in meeting Michigan's growing economy, based on the following expected trends:

1. An increase of at least 2 cents /kWh in "on-peak" utility energy rates due to environmental regulations, renewable portfolio standards, and increased maintenance costs for older coal plants. See Table 3.6 to see the impact of a 2-cent-per-kWh increase in on-peak energy cost.
2. Lower first costs of CHP systems, combined with improved performance.

These two trends can increase DE penetrations that could greatly reduce peak-load growth. Overall, DE penetration rates are expected to be less than the anticipated electric load growth, ensuring that distribution system electricity sales still increase.

Typical Country wide Rate based on 2080 Hrs/yr (i.e. 4 cents/kWh)					
Buildings w/ IC Engine CHP Gensets	**BAU**	**IBR**	**IBRT**	**Peak Dmd**	**On-Site kW**
Existing School	6	4	2	1376	550
Existing School w/ Abs. Chiller	7	5	3	1376	550
Existing Newspaper Press	9	8	3	970	550
Existing Newspaper Press w/ Abs. Chiller	9	8	4	970	550
Existing Low-Rise Office	NE	NE	9	205	190
Existing Light Industry *	3	2	2	970	550
Existing Light Industry w/ Abs. Chiller*	3	3	2	970	550
Existing Data Center	8	6	3	3609	2000
Existing Data Center w/ Abs. Chiller	7	6	3	3609	2000
New School	5	2	2	1376	550
New School w/ Abs. Chiller	6	3	2	1376	550
New Newspaper Press	8	4	2	970	550
New Newspaper Press w/ Abs. Chiller	9	6	3	970	550
New Low-Rise Office	NE	12	8	205	190
New Light Industrial *	3	2	1	970	550
New Light Industrial w/ Abs. Chiller*	3	2	1	970	550
New Heavy Industrial *	1	1	1	5002	2000
New Heavy Industrial w/ Abs. Chiller*	2	1	1	5002	2000
New High-Rise Office	9	5	2	985	550
New High-Rise Office w/ Abs. Chiller	9	5	3	985	550
New Hospital	4	2	1	2540	2000
New Hospital w/ Abs. Chiller	4	2	2	2540	2000
New Data Center	4	2	1	3609	2000
New Data Center w/ Abs. Chiller	4	2	1	3609	2000

Table 3.6. Payback Times for Buildings on Model Feeder Based on More Typical On-Peak Energy Rates

Figure 3.6 shows payback times for the buildings on the model feeder comparing the standard DTE rate to the DTE rate with 2 cents per kWh added to the energy charge. Payback times are based on an analysis for Michigan climate. Warmer climates would change load curves and energy requirements, thus affecting economics.

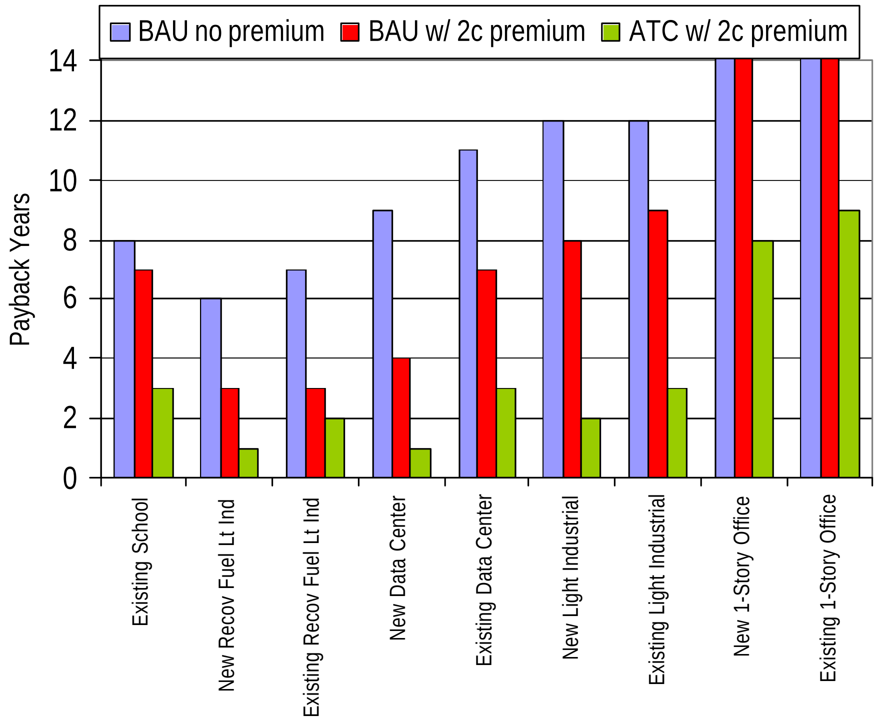


Figure 3.6 Paybacks by Building Type for Alternative Electric Cost

4.0 Conclusions

The study revealed that DE penetration on the selected feeder is not expected to forestall the need to upgrade the grid circuit capacity unless significant changes are made to remove barriers to the implementation of DE and to improve DE technology to lower its cost and improve its efficiency. As expected, the economics are greatly affected by the installed cost of the equipment.

However, the study showed that significant DE penetration in the form of CHP may increase overall utility grid utilization by helping to alleviate peak electric demand periods. In addition to slowing the growth in peak demand, DE can still allow for increased incremental and base load sales, thereby improving grid utilization while avoiding the need for grid capacity upgrades.

Analyzing the economics for customers on the feeder circuit with respect to the three scenarios, it was found that improved business rules and, to a greater extent, technical advances will pave the way for increased DE penetration. Several key points were concluded as follows:

- Recent advances in lean-burn reciprocating engine technology have decreased installed costs by 30% in the past two years. Under the Business as Usual scenario, DE penetration with this technology is possible but may not be probable. Installed costs generally remain higher than the economical range of $400-$600/kW.

- Under the Improved Business Rules scenario, payback times improve, positioning the market for future technological advances. Installed costs are closer, but still remain higher than the economical range of $400-$600/kW.
- Under the Improved Business Rules and Technologies scenario, payback times improve dramatically. Installed costs that would make DE ventures economical now range from $600 to $800/kW.
- With advances, fuel cell technology would become economical when a recoverable fuel is available (e.g. biogas, refinery byproducts, etc).
- Payback times are reduced by 25% to 50% by adding 2 cents to the energy charge portion of the utility's rate structure, which is more representative of rates seen in more heavily natural-gas-based generation areas, such as Texas, the Northeast and California. This increase would provide greater DE penetration.
- Under maximum penetration in the Improved Business Rules and Technologies scenario, CHP on this feeder alone would save enough fuel to provide energy for two new schools.
- Under maximum penetration in the Improved Business Rules and Technologies scenario, CHP on this feeder alone would reduce carbon dioxide emissions by the equivalent of more than 1,000 typical sport-utility vehicles.
- Certain CHP applications, particularly those with higher heating and cooling loads, would improve economic payback.
- Facilities with critical energy loads that are currently considering DE may penetrate the market if the added value of critical service and reliability were considered in the economics.

Although this study focused primarily on the customer's perspective of DE, observations were made with respect to the utility's standpoint as well. For example, the effect of a demand-response (DR) strategy was analyzed. (DR is the use of DE at peak demand periods solely to supply the power that the grid circuit cannot supply.)

Analysis of the model load duration curves revealed the following key points:

- Demand Response driven by customer economics alone would not be sufficient to keep the predicted 2015 peak load from exceeding the 16 MW capacity of the grid circuit.
- Use of CHP alone would also not be sufficient. About 80 hours per year of DR would still be required to clip the remaining peak demand on the 2015 curve.
- The combination of DR and CHP would just barely keep the peak demand on the feeder circuit below 16 MW, however significant energy efficiency would be gained.
- Additional building energy efficiency advances such as efficient lighting, solar photovoltaics, and advanced HVAC systems may further reduce the peak demands and provide greater power reserve margins.
- With both CHP and DR together, distribution system costs would fall, system stability could increase, and grid capacity expansions could be deferred.

- Reducing the standby charge for selected customers would be a sufficient price signal to encourage customers to add DR or CHP.
- Traditional rate design and Transmission and Distribution (T&D) costing discourage DE and preclude the achievement of its financial and energy efficiency benefits.
- If the value of environmental impact mitigation and customer reliability could be monetarily quantified, payback times would improve.
- Government incentives through the tax codes, Public Benefits Funds, or Renewable Portfolio Standards, may shorten payback times. These incentives are often targeted to specific technologies.

Despite the very competitive electricity rates for this particular feeder, there is a business case for DE. Providing R&D for advanced technology is a requirement. However, the marketplace must be prepared to accept these technology advances by addressing regulatory issues in the near term.

APPENDIX 1: ANALYSIS ASSUMPTIONS

General Assumptions

2015 – Scenario 1: "Business as Usual"	2015 – Scenario 2: "Improved Business Rules"	2015 – Scenario 3: "Improved Business Rules and Technologies"
4%/yr growth in peak load & energy consumption first five, 3% for the duration	← ditto	← ditto
2%/yr load growth on rest of service territory	← ditto	← ditto
No hydrogen infrastructure or vehicle fueling	← ditto	← ditto
No utility/customer benefit sharing opportunities	Extensive customer benefit sharing opportunities	← ditto
DR support services scant and expensive	Well established DR support services	← ditto
Natural gas is generally available	← ditto	← ditto
Fuel is available; price is stable and non-curtailable	← ditto	← ditto
DR technology cost & performance at 2002 levels	← ditto	Substantial cost & performance improvements
DRs are stationary (not transportable)	Portable power versions available	← ditto
All financial calculations in 2002 $	← ditto	← ditto
inflation is 2% per year	← ditto	← ditto
No NIMBYism	← ditto	← ditto
No locational pricing/ or RTP	Locational and RT pricing	Locational and RT pricing
NOX non-attainment area	NOx attainment area (output)	NOx attainment area (output)

Customer Assumptions

2015 – Scenario 1: "Business as Usual"	2015 – Scenario 2: "Improved Business Rules"	2015 – Scenario 3: "Improved Business Rules and Technologies"
Commercial and light industrial electric energy rates are $.0227/kWh on-peak and $.020/kWh off-peak w/ rate reductions	← ditto	← ditto
Demand charges =13.08$/kW-mo w/ rate reductions	DUA "Locational Peak Rate" $0.78/kWh for 200 hours. No demand charge for participating and complying customers.	← ditto
Standby rate = 2.98$/kW-mo w/ rate reductions	Standby rate = 2.98$/kW-mo…for now	← ditto
On-peak rate period is 11 am - 7 pm (weekdays and non-holidays)	On-peak rate period is 9 am - 7 pm (weekdays and non-holidays)	← ditto
Geographically uniform prices	Locational based pricing provides a x cent increase in constrained areas	Locational based pricing provides a x cent increase in constrained areas
Buyback rates = today's energy rates	Buyback rates = energy rates plus adder to account for line losses	← ditto
No net metering	Net metering for units below X kW	← ditto
No appreciable DG/CHP installed (DTE)	output	← ditto
No distributed storage installed	output	← ditto
Fuel available at customer site (firm service)	Fuel available at customer site (firm service)	Fuel available at customer site (firm service)
Firm natural gas cost 5$/mmbtu Feb-Dec firm natural gas cost 5$/mmbtu Jan	← ditto	← ditto
CHP technical market potential is 2000 MW	output	← ditto
Standby generators, but no activation program	Demand response programs in place	Demand response program in place
Utility pay-outs for Demand Response ____ $/kW	Utility pay-outs for Demand Response ____ $/kW	Utility pay-outs for Demand Response ____ $/kW
No exit fee or CTC	← ditto	← ditto
Reliability of grid is .03% (3 hours/yr)	← ditto	← ditto
Reliability of peak DG system 95 % DG Outage = (Standby + 1.00)/kW/mo	Reliability of peak DG system 96 % DG Outage = (Standby + 0.80)/kW/mo	Reliability of peak DG system 99 % DG Outage = (Standby + 0.20)/kW/mo
Value of service = $20/kW for critical buildings, $5/kW for non-critical buildings. Power quality included in value of service	← ditto ← ditto	← ditto ← ditto

2015 – Scenario 1: "Business as Usual"	2015 – Scenario 2: "Improved Business Rules"	2015 – Scenario 3: "Improved Business Rules and Technologies"
Candidate customer DR applications: energy use reduction, demand charge reduction, standby generator activation, CHP, reliability/PQ	← ditto	← ditto
Customer payback is calculated and used to determine penetration	← ditto	← ditto
Single winner by lowest payback	← ditto	← ditto
Penetration value related to payback (5 year)	← ditto	← ditto
Institutional penetration value related to payback (10 year)	← ditto	← ditto
Interconnection costs are included in barrier cost, delays are 6 months	Minimal	← ditto
Siting costs are included in barrier cost, delays are 6 months	Minimal	← ditto
Barrier costs are included in the technology assumptions (first costs)	<500kW: $140/kW, >500 to 2MW: $125/kW, >2M: $60/kW (derived from data in the Making Connections report)	← ditto
Barrier cost reduced by 10% for new buildings	← ditto	← ditto
Cost of capital is 10% per year	← ditto	← ditto
Standard depreciation for CHP	Accelerated depreciation for CHP	← ditto
Depreciation 15 yrs; book method is sum	← ditto	← ditto
Finance period 7 years	← ditto	← ditto
% financed is 80%	← ditto	← ditto
Tax Rate is 15% and method is SL	← ditto	← ditto
Inflation is 2% per year	← ditto	← ditto

Utility Assumptions

2015 – Scenario 1: "Business as Usual"	2015 – Scenario 2: "Improved Business Rules"	2015 – Scenario 3: "Improved Business Rules and Technologies"
Distribution-only utility - generation costs "flow-thru" to the customer	← ditto	← ditto
No bi-directional flow	← ditto	← ditto
1 feeder: 1/3 commercial, 2/3 industrial	← ditto	← ditto
No geographically targeted load management programs	Geographically targeted load management programs	← ditto
Load growth: 4%/yr 2002-2006; 3%/yr 2007-2011; 2%/yr 2012-2015	← ditto	← ditto
Substation "load in play" = 9.5 MW	← ditto	← ditto
Circuit "load in play" = 2.7 MW	← ditto	← ditto
16 MW rating and 12 MW coincident peak load on Pioneer circuit in Ann Arbor, Michigan	← ditto	← ditto
One major 120kV to Pioneer substation with four 13kV circuits	← ditto	← ditto
Pioneer circuit at 75% capacity and substation at 75.3% of firm rating	← ditto	← ditto
200 hours required to clip peaks by 20% for residential (awaiting LDC from DTE)	← ditto	← ditto
Feeder asset utilization 98%		
Cost of upgrade=$115/kW transmission; $288/kW distribution	← ditto	← ditto
Upgrade factor for T&D investments is 50%	← ditto	← ditto
25% technical limit on DER installations (DTE)	DTE to check cost required to make it 40%	← ditto
Land available for DR, sufficient for T&D deferrals	← ditto	← ditto
DR siting costs are ___ $/kW	DR siting costs are lower by 50%	← ditto
Curtailable/interruptible rates are not applicable	Curtailable/interruptible rates are applicable	← ditto

Average SAIDI and SAIFI indices are: __________ (Need DTE data)	**Average SAIDI and SAIFI indices are improved (output)**	**Average SAIDI and SAIFI indices are improved further (output)**
Emissions from central generation increase due to increased Midwest coal use	**Lower emissions from central generation increase due to decreased Midwest coal use (output)**	**Even lower emissions from central generation increase due to decreased Midwest coal use (output)**
Regulation regime: 3-yr. rate case, ROI	**Regulation regime: 3-yr. rate case, PBR**	**← ditto**
No locational pricing/or RTP	**Locational and RT pricing**	**Locational and RT pricing**
Grid utilization (average) about 60%	**Increased? (output)**	**Further increased? (output)**
Utility does consider DR as a viable alternative in its planning processes: G, T, D	**← ditto**	**← ditto**
Utility allowed to own & operate DR (rate-based)	**← ditto**	**← ditto**
Utility DR ownership on customer sites allowed	**← ditto**	**← ditto**
Utility can contract with customer for DR benefits	**← ditto**	**← ditto**
Real-time feeder, load, DR operational status info not available	**← ditto**	**Real-time feeder, load, DR operational status info is available**
Real-time feeder, load, DR control capability does not exist	**← ditto**	**Real-time feeder, load, DR control capability does exist**
Candidate utility DR applications: G peak shaving T peak shaving D peak shaving T&D deferral reliability enhancement power quality (PQ)	**← ditto**	**← ditto**
Cost of capital is 10% per year (DTE to verify and provide fixed charge rate) Fixed rate charge is 0.15 for the utility to own distributed resources	**← ditto ← ditto**	**← ditto ← ditto**

Technology Assumptions
Turbines

Business as Usual							Advanced Technologies						
Item	<500 kW	Ref	>500 to 2000 kW	Ref	>2000 kW	Ref	Item	<500 kW	Ref	>500 to 2000 kW	Ref	>2000 kW	Ref
Capacity, kW	100	1	1000	3	5000	7	Capacity, kW	100		1000	5	5000	8
Equip/Interconnect/HR ($/kW)	$1,100	1	$1,180	3	$660	7	Equip/Interconnect/HR ($/kW)	$650	2	$1,000	5	$570	8
Installation ($/kW)	$240	1	$460	3	$260	7	Installation ($/kW)	$210	2	$355	5	$225	8
Other/Eng/Fin/PM ($/kW)	$425	1	$290	3	$150	7	Other/Eng/Fin/PM ($/kW)	$240	2	$220	5	$130	8
Total ($/kW)	$1,765	1	$1,930	3	$1,070	7	Total ($/kW)	$1,100	2	$1,575	5	$925	8
Electric Efficiency (HHV)	26.0%	1	21.9%	3	27.1%	7	Electric Efficiency (HHV)	35.0%	2	26.0%	5	32.1%	8
RH Efficiency – Exhaust	42.0%	1	45.5%	3	42.0%	7	RH Efficiency - Exhaust	36.0%	2	45.0%	5	40.0%	8
RH Efficiency – Water	N/A		N/A		N/A		RH Efficiency - Water	N/A		N/A		N/A	
Recoverable Heat (MMBtu/hr)	0.55	1	7.09	3	26.6	7	Recoverable Heat (MMBtu/hr)	0.35	2	5.80	5	21.4	8
Heating Cost ($/kW)	inc	1	inc	3	inc	7	Heating Cost ($/kW)	inc.	2	inc	5	inc	8
w/HP ($/kW)	$1,765		$1,930		$1,070		w/HP ($/kW)	$1,100	2	$1,575		$925	
Cooling Single Stage (tons)	31		414		1,553		Cooling Single Stage (tons)	35.09		426.5		2,131	
Cooling Cost ($/Ton)	1,200		360		250		Cooling Cost ($/Ton)	1080		324		225	
w/CHP ($/kW)	$2,137		$2,079		$1,148		w/CHP ($/kW)	$1,479		$1,713		$1,021	
NOx Uncontrolled (lb/MWh)	0.7	1	2.43	3	1.16	7	NOx Uncontrolled (lb/MWh)	0.1	2	0.7	5	0.11	8
NOx Controlled (lb/MWh)	NA		0.24	4	0.11	4	NOx Controlled (lb/MWh)	NA		0.1	6	0.03	4
Control Cost ($/kW)	NA	NA	162	4	90	4	Control Cost ($/kW)	NA		60	6	40	4
O&M Cost ($/kWh)	0.015	1	0.0096	3	0.0059	7	O&M Cost ($/kWh)	0.014	2	0.008	5	0.0049	8
CO (lb/MWh)	0.45	1	0.71	3	0.56	7	CO (lb/MWh)	0.32		0.27	5	0.56	8
CO_2 (lb/MWh)	1535	1	1815	3	1480	7	CO_2 (lb/MWh)	1140	2	1535	5	1250	8

Engine Rich Burn

Business as Usual							Advanced Technologies						
Item	<500 kW	Ref	>500 to 2000 kW	Ref	>2000 kW	Ref	Item	<500 kW	Ref	>500 to 2000 kW	Ref	>2000 kW	Ref
Capacity, kW	100	1					Capacity, kW	100					
Equip/Interconnect/HR ($/kW)	$725	1					Equip/Interconnect/HR ($/kW)	$615	3				
Installation ($/kW)	$360	1					Installation ($/kW)	$205	3				
Other/Eng/Fin/PM ($/kW)	$410	1					Other/Eng/Fin/PM ($/kW)	$230	3				
Total ($/kW)	$1,495	1					Total ($/kW)	$1,050	3				
Electric Efficiency (HHV)	29.0%	1					Electric Efficiency (HHV)	33.0%	3				
RH Efficiency - Exhaust	17.0%	1					RH Efficiency - Exhaust	20.0%	3				
RH Efficiency - Water	31.0%	1					RH Efficiency - Water	33.0%	3				
Recoverable Heat (MMBtu/hr)	0.57	1					Recoverable Heat (MMBtu/hr)	0.55	3				
Heating Cost ($/kW)	incl	1					Heating Cost ($/kW)	inc.	3				
w/HP ($/kW)	$1,495	1					w/HP ($/kW)	$1,050	3				
Cooling Single Stage (tons)	32						Cooling Single Stage (tons)	54.6					
Cooling Cost ($/Ton)	1,260						Cooling Cost ($/Ton)	1134					
w/CHP ($/kW)	$1,898						w/CHP ($/kW)	$1,669					
NOx Uncontrolled (lb/MWh)	44	1					NOx Uncontrolled (lb/MWh)	34	3				
NOx Controlled (lb/MWh) - TWC	0.44	2					NOx Controlled (lb/MWh) - TWC	0.3	2,3				
Control Cost ($/kW)	65	2					Control Cost ($/kW)	40	2				
O&M Cost ($/kWh)	0.018	1					O&M Cost ($/kWh)	0.014	3				
CO (lb/MWh) - with TWC	1.7	1					CO (lb/MWh) - with TWC	0.3	3				
CO2 (lb/MWh)	1375	1					CO2 (lb/MWh)	1210	2				

Engine Lean Burn

Business as Usual							Advanced Technologies						
Item	<500 kW	Ref	>500 to 2000 kW	Ref	>2000 kW	Ref	Item	<500 kW	Ref	>500 to 2000 kW	Ref	>2000 kW	Ref
Capacity, kW	300	1	800	3	5000	5	Capacity, kW	300	2	800	4	5000	6
Equip/Interconnect/HR ($/kW)	$500	1	$400	3	$500	5	Equip/Interconnect/HR ($/kW)	$425	2	$370	4	$440	6
Installation ($/kW)	$360	1	$340	3	$215	5	Installation ($/kW)	$270	2	$260	4	$180	6
Other/Eng/Fin/PM ($/kW)	$320	1	$230	3	$160	5	Other/Eng/Fin/PM ($/kW)	$240	2	$220	4	$140	6
Total ($/kW)	$1,180	1	$970	3	$875	5	Total ($/kW)	$935	2	$850	4	$760	6
Electric Efficiency (HHV)	31.1%	1	33.3%	3	39.0%	5	Electric Efficiency (HHV)	36.0%	2	42.0%	4	50.0%	6
RH Efficiency - Exhaust	25.0%	1	25.9%	3	16.4%	5	RH Efficiency - Exhaust	26.0%	2	27.0%	4	18.0%	6
RH Efficiency - Water	21.0%	1	16.8%	3	18.8%	5	RH Efficiency - Water	22.0%	2	19.0%	4	19.0%	6
Recoverable Heat (MMBtu/hr)	1.51	1	3.50	3	15.4	5	Recoverable Heat (MMBtu/hr)	1.35	2	3.00	4	13.0	6
Heating Cost ($/kW)	inc	1	inc	3	inc	5	Heating Cost ($/kW)	inc.	2	inc	4	inc	6
w/HP ($/kW)	$1,180		$970		$875		w/HP ($/kW)	$935	2	$850		$760	
Cooling Single Stage (tons)	88		189		786		Cooling Single Stage (tons)	136.5		299		1,399	
Cooling Cost ($/Ton)	770		550		267		Cooling Cost ($/Ton)	693		495		240	
w/CHP ($/kW)	$1,406		$1,100		$917		w/CHP ($/kW)	$1,250		$1,035		$827	
NOx Uncontrolled (lb/MWh)	5.9	1	3	3	1.48	5	NOx Uncontrolled (lb/MWh)	1.48	2	0.74	4	0.74	6
NOx Controlled (lb/MWh)	0.5	7	0.5	7	0.5	7	NOx Controlled (lb/MWh)	0.16	7	0.07	7	0.07	7
Control Cost ($/kW)	350	7	225	7	140	7	Control Cost ($/kW)	160	7	160	7	110	7
O&M Cost ($/kWh)	0.013	1	0.01	3	0.0095	5	O&M Cost ($/kWh)	0.01	2	0.009	4	0.009	6
CO (lb/MWh)	9.45	1	7.7	3	6.5	5	CO (lb/MWh)	4.4	2	4.4	4	3	6
CO2 (lb/MWh)	1380	1	1200	3	1025	5	CO2 (lb/MWh)	1110	2	950	4	800	6

Fuel Cell

Business as Usual							Advanced Technologies						
Item	<500 kW	Ref	>500 to 2000 kW	Ref	>2000 kW	Ref	Item	<500 kW	Ref	>500 to 2000 kW	Ref	>2000 kW	Ref
Capacity, kW	200	1					Capacity, kW	250	2				
Equip/Interconnect/HR ($/kW)	$3,850	1					Equip/Interconnect/HR ($/kW)	$1,100	2				
Installation ($/kW)	$280	1					Installation ($/kW)	$240	2				
Other/Eng/Fin/PM ($/kW)	$370	1					Other/Eng/Fin/PM ($/kW)	$320	2				
Total ($/kW)	$4,500	1					Total ($/kW)	$1,660	2				
Electric Efficiency (HHV)	36.0%	1					Electric Efficiency (HHV)	49.0%	2				
RH Efficiency - Exhaust	19.5%	3					RH Efficiency - Exhaust	18.0%	3				
RH Efficiency - Water	19.5%	3					RH Efficiency - Water	18.0%	3				
Recoverable Heat (MMBtu/hr)	0.74	1					Recoverable Heat (MMBtu/hr)	0.45	2				
Heating Cost ($/kW)	incl	1					Heating Cost ($/kW)	inc.	2				
w/HP ($/kW)	$4,500	1					w/HP ($/kW)	$1,660	2				
Cooling Single Stage (tons)	24						Cooling Single Stage (tons)	40					
Cooling Cost ($/Ton)	1,400						Cooling Cost ($/Ton)	1,260					
w/CHP ($/kW)	$4,668						w/CHP ($/kW)	$1,862					
NOx Uncontrolled (lb/MWh)	0.04	1					NOx Uncontrolled (lb/MWh)	0.04	2				
NOx Controlled (lb/MWh)	na						NOx Controlled (lb/MWh)	na					
Control Cost ($/kW)	na						Control Cost ($/kW)	na					
O&M Cost ($/kWh)	0.029	1					O&M Cost ($/kWh)	0.012	2				
CO (lb/MWh) - with TWC	0.05	1					CO (lb/MWh) - with TWC	0.03	2				
CO2 (lb/MWh)	1140	1					CO2 (lb/MWh)	835	2				

Dual Fuel Peaker

2015 – Scenario 1: "Business as Usual"							2015 – Scenario 3: "Improved Business Rules and Technologies"						
Item	<500 kW	Ref	>500 to 2000 kW	Ref	>2000 kW	Ref	Item	<500 kW	Ref	>500 to 2000 kW	Ref	>2000 kW	Ref
kW	500						kW						
Equip/Interconnect ($/kW)	300	9					Equip/Interconnect ($/kW)						
Installation ($/kW)	170	9					Installation ($/kW)						
Other/Eng/Fin/PM ($/kW)	170						Other/Eng/Fin/PM ($/kW)						
Total ($/kW)	640		0		0		Total ($/kW)	0		0		0	
Electric Efficiency (HHV)	37.0%						Electric Efficiency (HHV)						
RH Efficiency - Exhaust	N/A		N/A		N/A		RH Efficiency - Exhaust	N/A		N/A		N/A	
RH Efficiency - Water	N/A		N/A		N/A		RH Efficiency - Water	N/A		N/A		N/A	
Recoverable Heat (Btus)	N/A		N/A		N/A		Recoverable Heat (Btus)	N/A		N/A		N/A	
Heating Cost ($/kW)	N/A		N/A		N/A		Heating Cost ($/kW)	N/A		N/A		N/A	
w/HP ($/kW)	N/A		N/A		N/A		w/HP ($/kW)	N/A		N/A		N/A	
Cooling Single Stage (tons)	N/A		N/A		N/A		Cooling Single Stage (tons)	N/A		N/A		N/A	
Cooling Cost ($/Ton)	N/A		N/A		N/A		Cooling Cost ($/Ton)	N/A		N/A		N/A	
w/CHP ($/kW)	N/A		N/A		N/A		w/CHP ($/kW)	N/A		N/A		N/A	
Barrier Cost Credit							Barrier Cost Credit						
NOx Uncontrolled (lb/MWh)	24.00	9					NOx Uncontrolled (lb/MWh)						
NOx Controlled (lb/MWh)	4.00	9					NOx Controlled (lb/MWh)						
Control Cost ($/kW)							Control Cost ($/kW)						

O&M Cost ($/kWh)							**O&M Cost ($/kWh)**						
CO (lb/MWh)							**CO (lb/MWh)**						
CO2 (lb/MWh)							**CO2 (lb/MWh)**						

APPENDIX 2: DTE RATE STRUCTURE

Electric

More than 50kW capacity
Minimum 480v service
Service less than 24kV (Primary Service)
Service metered on secondary side of transformer
Less than 10MW demand

Primary Service

	Rate D6 Charges	Rate	Units
x	Service Charge	275	$/month
x	Demand Charges	14.25	$/kW
x	Maximum Demand Charge	3.75	$/kW
x	On-peak Energy Charge	0.02471	$/kWh
x	Off-peak Energy Charge	0.02171	$/kWh
	Base Rate reduction	-3.227%	$/month
	Securitization Reduction	-5%	$/month
	Power Supply Cost Recovery	0.00204	$/kWh
	Nuclear Decommissioning	0.0006985	$/kWh
x	Securitization Bond Charge	0.00392	$/kWh
x	Securitization Bond Tax Charge	0.00097	$/kWh

Base Rate Reduction applies to items marked with x
5% applies to total bill excluding taxes

Standby Service

	Rate R3 Charges	Rate	Units
x	Service Charge	210	$/month
x	Gen Res Fee	0.86	$/ kWgen
x	Standby Charge	3.25	$/kW
x	Daily On-peak Standby Demand	0.9	$/kW/day
x	Daily On-peak Maint Demand	0.48	$/kW/day
x	On-peak Energy Charge	0.02471	$/kWh
x	Off-peak Energy Charge	0.02171	$/kWh
	Base Rate reduction	-3.227%	$/month
	Securitization Reduction	-5%	$/month
	Power Service Charge	0.00204	$/kWh
	Nuclear Decommissioning	0.0006985	$/kWh
x	Securitization Bond Charge	0.00392	$/kWh
x	Securitization Bond Tax Charge	0.00097	$/kWh

Gas

Rate Schedule #1 Charges	Rate	Units
Customer Charge	15	$/month
Distribution Charge	0.18179	$/100cf
Recovery factor - Jan	0.362	$/100cf
Recovery Factor - Feb-Dec	0.438	$/100cf
Distribution Charge	0.17313	$/Therm
Recovery factor - Jan	0.34476	$/Therm
Recovery Factor - Feb-Dec	0.41714	$/Therm

1. B-4.4 SCHEDULE OF ON-PEAK HOURS:

On-peak hours are those hours between 1100 hours and 1900 hours each day, Monday through Friday, legal holidays excluded. The following will be considered legal holidays for the purpose of applying this schedule: New Year's Day, Good Friday, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, Christmas Day. Monday" holidays, where legally recognized, will be

Notes:
1. Generation reservation pays for or cost of reserving generation resources to serve the load when the customers generator is not operating at it's expected level. The charge is 0.86/kw/mo of Standby Contract Capacity (SCC).
2. Daily on-peak standby demand charges of 0.90/kw/day is calculated daily by determining if the generator is operating below SCC. If it is below SCC, then it's calculated by taking the difference of SCC and generator output during on-peak (i.e. if 1 MW SCC and gen only generates 800 kW then $0.9*200= $180 demand charge). If the sum of the monthly demand charge (on-peak) is greater than generator reservation fee, the customer pays the demand charge and not the generation reserve charge.
3. The maintenance demand is calculated for the up to 20 maintenance days that the facility has requested plus day after Thanksgiving and over the x-mas holidays (12/24 - 1/1).
4. If the units are down for a month, the customer is treated as a D6 rate customer.
5. The Standby charge of $3.25 is considered to be T&D cost recovery.

APPENDIX 3: THE BUILDING ENERGY ANALYZER

Comparing Energy Options

Estimate annual or monthly loads and costs associated with air-conditioning, heating, and on-site power generation with *Building Energy Analyzer*ä. Compare the performance of standard and high efficiency electric chillers, variable speed electric chillers, absorption chillers, engine chillers, thermal storage, on-site generators, heat recovery, or desiccant systems.

Use to Estimate Energy Loads and Costs

Estimate annual or monthly loads and costs associated with air-conditioning, heating, power generation, thermal storage and heat recovery systems for a given building and location with *Building Energy Analyzer*ä. Develop a better understanding of what new building heating, cooling, and power technology can mean for your clients. Prepare side-by-side economic comparisons of different energy options and equipment life cycle cost analysis, perfect for client presentations.

Use as a Marketing Tool

Easily perform quick-to-use economic analysis for the customer's utility rates, location, and building type. Tailor your analysis to the specifics of the customer's facility.

Develop Sales Literature

Use the program's typical buildings to prepare marketing literature for local weather condition by building type (schools, retail, etc,) Train new marketing staff on cost saving opportunities for your customers.

Use to Focus Your Marketing Effort

Test the economic viability of a wide range of different systems. Pick the most attractive application and building type, and develop your marketing focus. Perfect for ESCO marketers.

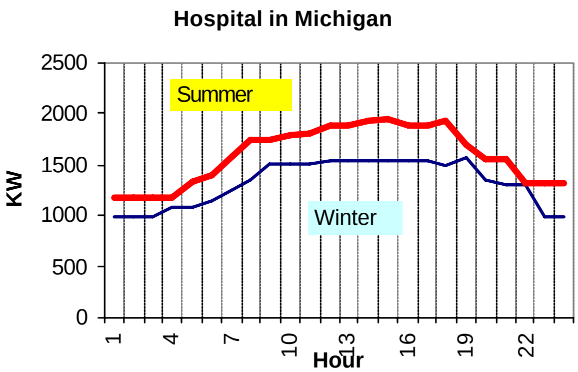
Summary of Building Data for this Study

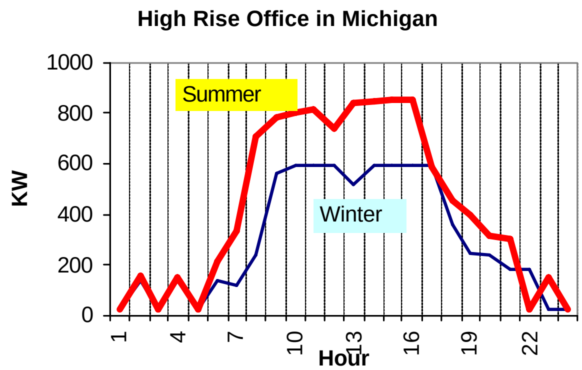
The Building Energy Analyzer software comes pre-set with a variety of 'generic' buildings. The Table below shows several of these 'generic' buildings as well as their typical loads. The load of these buildings take into account the climate and typical set-up and operation of similar real buildings.

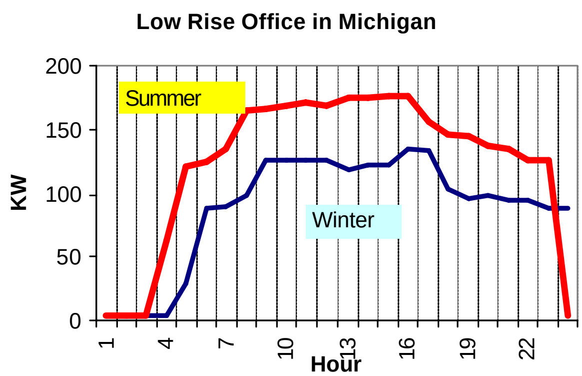
Building Type	**KW Load**
Hospital	2,394
Office - High-Rise	1,715
School	1,376
Hotel - Large	1,256
Industrial Application	970
Ice Arena	504
Retail Store	346
Warehouse - Refrigerated	263
Supermarket	256

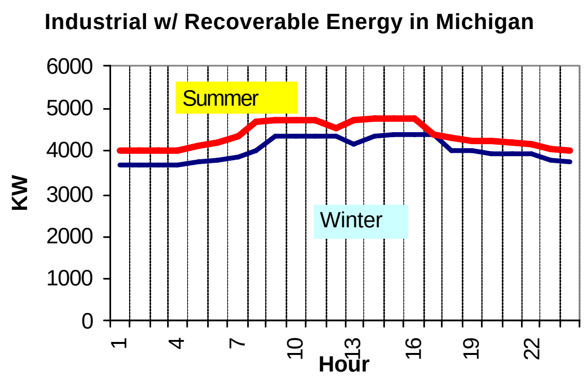
Theater	213
Office - Low-Rise	205
Hotel - Small	203
Nursing Home	166
Restaurant - Full Service	88
Restaurant - Quick Service	35

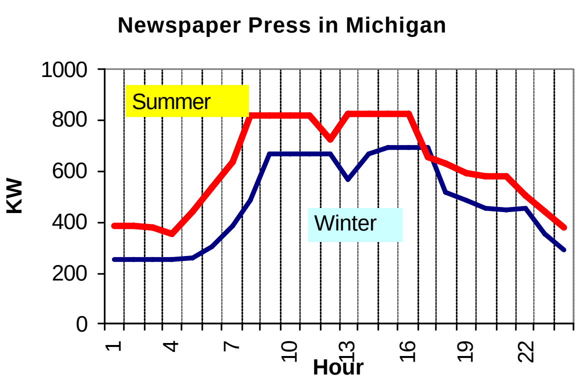
APPENDIX 4: TYPICAL MICHIGAN BUILDING LOAD PROFILES

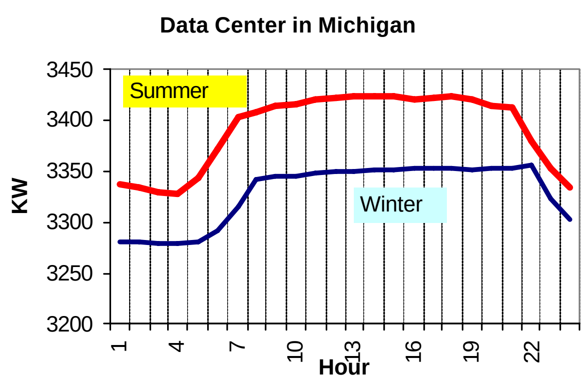


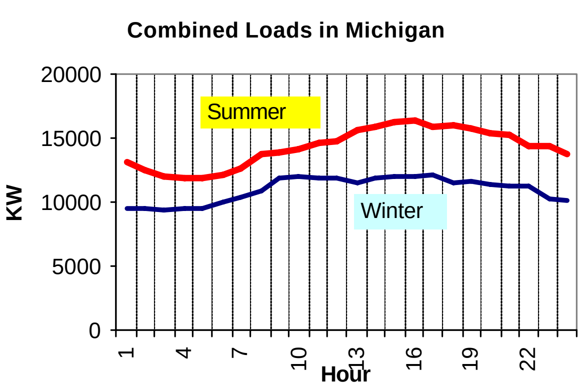


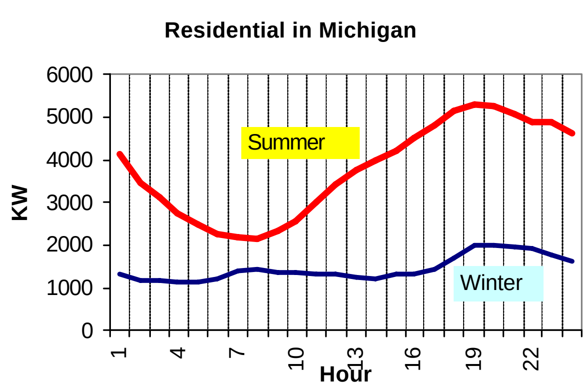












APPENDIX 5: INDUSTRIAL POTENTIAL IN DTE SERVICE AREAS

The following table is a summary of facilities within Detroit Edison's Service Area. This data is provided by Dun & Bradstreet Marketplace database (year October 2002).

Facilities by Type in DTE's Service Area

MANUFACTURING	Facilities	**INSTITUTIONAL**	Facilities
FOOD	353	WATER SUPPLY	29
TEXTILE MILLS	112	REFUSE SYSTEMS	257
APPAREL	407	NURSING HOMES	217
LUMBER, WOOD	338	HOSPITALS	210
FURNITURE	274	SCHOOLS	2,011
PAPER	172	COLLEGES	340
PRINTING	1,749	MUSEUMS	138
CHEMICAL	491	ZOOS & GARDENS	8
PETROLEUM	94	PRISONS	33
RUBBER & PLASTICS	753		
LEATHER	40	**COMMERCIAL**	
STONE, GLASS, CONCRETE	353	REFRIG WAREHOUSES	18
PRIMARY METALS	384	GROCERIES	1,847
FABRICATED METALS	1,744	RESTAURANTS	6,555
MACHINERY	3,059	NONRESIDENTIAL BLDGS	822
ELECTRICAL EQUIPMENT	702	SHOPPING CENTERS	9
TRANSPORTATION EQUIP	839	HOTELS	615
INSTRUMENTATION	510	LAUNDRIES	1,291
MISC. MAUFACTURING	836	CAR WASHES	451
		HEALTH CLUBS	259

APPENDIX 6: ACCRONYMS AND ABBRIEVIATIONS

ATC	Advanced Technology Case (same as IBR&T)
BAU	Business as Usual scenario
Btu	British thermal units
CHP	Combined heating and power (with recoverable heat distribution to heating or cooling equipment)
CHP/C	CHP with absorption chillers used for cooling
CO	Carbon monoxide
CO2	Carbon dioxide
DE	Distributed energy
DER	Distributed energy resources
DOE	U.S. Department of Energy
DR	Demand response, the use of DE at peak demand periods solely to supply the power that the grid circuit cannot supply.
DTE	DTE Energy Company, parent company of Detroit Edison
DUA	Distributed Utility Associates
EE	Energy efficient technology
Eh	Extending on-peak hours
GTI	Gas Technology Institute
Hrs	hours
HVAC	Heating, ventilation, and air conditioning
IBR	Improved Business Rules scenario
IBR&T	Improved Business Rules and Technologies scenario
kW	Kilowatts
kWh	Kilowatt hours
Lt Ind	Light industry
Mo	month
MW	Megawatts
NOx	Nitrogen oxides
O&M	Operation and maintenance
PV	solar photovoltaics

Recoverable fuel	A free, or almost free fuel derived from waste, such as biogas or refinery byproducts
SOx	Sulfur oxides
T&D	Transmission and distribution
UPS	Uninterruptible power supply
Yr	year

APPENDIX 7: REFERENCES

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