Kentucky Power Company

REQUEST

Identify the person having primary responsibility for the utility resource plan.

RESPONSE

Timothy C. Mosher, President and Chief Operating Officer has the primary responsibility of KPCo's resource plan. Scott C. Weaver, Managing Director of Resource Planning & Operational Analysis, has the day-to-day and overall coordination responsibility for the AEP System.

WITNESS: Timothy C. Mosher/Errol K Wagner

Kentucky Power Company

REQUEST

Identify the person or persons having primary responsibility of the utility financial forecasts and strategic plan or strategic planning documents.

RESPONSE

Timothy C. Mosher, President and Chief Operating Officer has the primary responsibility of KPCo's financial forecasts and strategic plan.

WITNESS: Timothy C. Mosher/Errol K Wagner

Kentucky Power Company

REQUEST

Identify the person or persons within the utility having primary responsibilities for siting new generation.

RESPONSE

Timothy C. Mosher, President and Chief Operating Officer has the primary responsibility of KPCo's siting for new generation.

WITNESS: Timothy C. Mosher/Errol K. Wagner

Kentucky Power Company

REQUEST

Identify the person or persons within the utility having the primary responsibility for conservation, energy efficiency, and demand-side management programs.

RESPONSE

Timothy C. Mosher, President and Chief Operating Officer has the primary responsibility of KPCo's conservation, energy efficiency and demand-side management programs. Donald Music, Principal DSM Coordinator, has the day-to-day responsibility of administrating the Company's DSM programs.

WITNESS: Timothy C. Mosher/Errol K Wagner

Kentucky Power Company

REQUEST

Identify and discuss all portions of the utility's current integrated resource plan which discuss future plans for implementation of demand-side management, renewable energy resources, and energy efficiency.

RESPONSE

Attachment A to this response is an excerpt from the 2007 AEP East IRP that discusses future plans for implementation of demand-side management, renewable energy resources and energy efficiency. Attachment B represents Kentucky Power's DSM impacts that are reflected in the 2007 AEP East IRP.

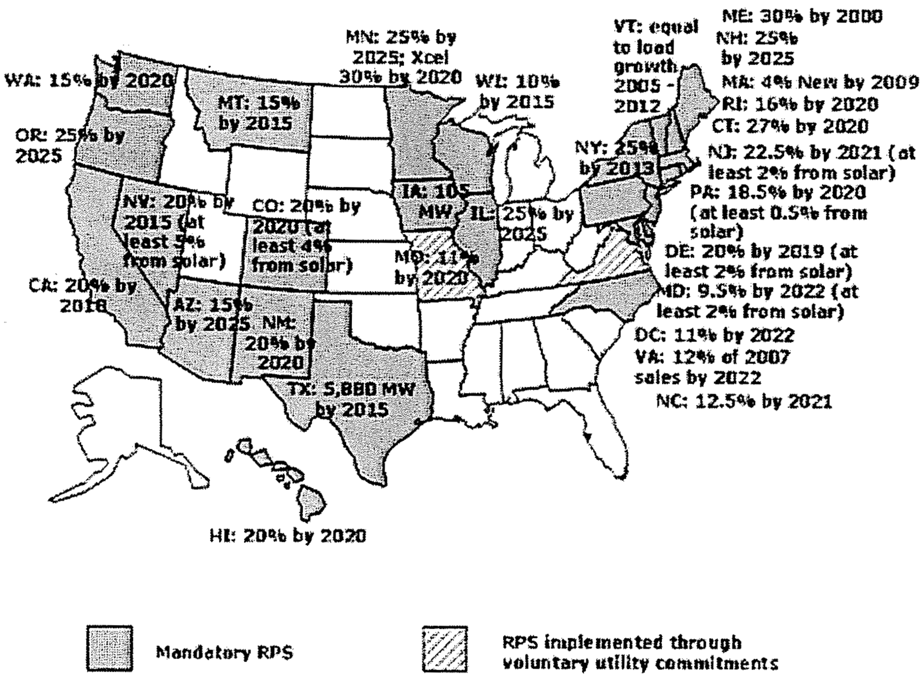
WITNESS: Timothy C. Mosher/Errol K Wagner

2.2.2.2 Renewable Portfolio Standards

As indentified in **Exhibit 4**, 25 states and the District of Columbia have set standards specifying that electric utilities generate a certain amount of electricity from renewable sources. Most of these requirements take the form of "renewable portfolio standards," or RPS, which require a certain percentage of a utility sales to ultimate customers come from renewable generation sources by a given date. The standards range from modest to ambitious, and definitions of renewable energy vary. Though climate change may not always be the primary motivation behind some of these standards, the use of renewable energy does deliver significant GHG reductions. For instance, Texas is expected to avoid 3.3 million tons of CO_2 emissions annually with its RPS, which requires 2,000 MW of new renewable generation by 2009.

At the federal level, a RPS ranging from 10-20% was proposed for inclusion in a new energy bill in 2007. However, a national RPS was not adopted in either Senate or House energy bills now being considered. Nonetheless, a federal RPS remains a possibility in a future session of Congress.

Exhibit 4: State Renewable Portfolio Standard (RPS) Commitments



Source: Pew Center on Global Climate Change

In recognition of the potential for a Federal RPS, or new state RPS requirements in AEP-served states, for this 2007 IRP cycle, AEP East (and West) long-term resource planning reflects:

- Achievement of 5% of energy sales through renewable resources by the year 2020 as a partial hedge for a possible RPS that could be 10-20%.
- A "no-regrets" position recognizing that the required introduction of such renewable generating resources may not result in the "least-cost" plan.

2.2.3 AEP's Voluntary Greenhouse Gas Mitigation Strategy

2.2.3.1 Plan through 2010

In 2003 AEP became a founding member of the Chicago Climate Exchange (CCX), the first voluntary GHG credit trading system in the United States. AEP committed to reduce or offset GHG emissions by 1% in 2003, 2% in 2004, 3% in 2005 and 4% in 2006 below baseline emission levels (an average of 1998-2001 annual emissions). These reductions are cumulative and are adjusted to account for divestitures, acquisitions or retirements of older power plants. In 2005, the company announced it would extend its CCX commitment to achieve further reductions or offsets in emissions during 2007-2010, reaching an annual target of 6% by 2010. CCX allows for flexible, cost-effective compliance with these targets by facilitating emissions trading (buying and selling of emission allowances) and banking of emission reductions (i.e., saving excess reductions in one year to use in a later year).

To meet our CCX obligation, we have taken a variety of actions. These include:

- Improving the efficiency of existing power plants to reduce CO_2 emissions per net kilowatt hour;
- Adding wind generation to our system, focused initially on more cost-effective projects in our western states, to displace the use of fossil fuel generation;
- Improving the availability and increasing generation from our Donald C. Cook nuclear power plant, which achieved record generation levels during 2004 and 2005;
- Retiring older and less efficient gas steam units in AEP's western (ERCOT) region (TNC and TCC) and, potentially, additional coal units in our eastern region, over and above Conesville Units 1&2, which were retired in 2006;
- Substantially reducing the leakage rate of sulfur hexafluoride (SF_6), a potent GHG, from transformers by approximately 90 percent; and
- Conserving trees and reforesting lands in the United States and internationally.

2.2.3.2 Post-2010 Plan

Despite our commitments to reduce our CO_2 emissions through 2010, if no further actions are taken we project that our emissions will begin to increase by 10 million to 15 million tons annually between 2011 and 2020 based on the prospect of building four new coal-fired power plants (East and West zones), as set forth in the previous IRP cycle. In response to our new plant construction and our vehicle and aircraft emissions, we will reduce approximately 5 million metric tons more of CO_2 per year through these offsets, including:

- Purchasing 1,000 MW of new wind power, including the company's first wind energy in its eastern states, to offset 2 million metric tons of CO_2;
- Investments in domestic offsets, such as methane capture and destruction from livestock manure or landfills, or other domestic projects, to offset 2 million metric tons of CO_2;
- Tripling our investment in forestry projects to offset 500,000 tons; and
- Offsetting all of our emissions from our corporate automotive fleet and aircraft to achieve a 200,000-ton reduction.

As discussed in the following section, additional actions, including a future carbon capture and storage program, will also help offset the anticipated growth in AEP's carbon footprint.

5.3 Current DSM/EE Programs

AEP-East has extensive peak demand shifting programs. In the East, these consist of "Interruptible" contracts with larger industrial customers and "Advanced Time of Day" (ATOD) pricing, which provides large users of electricity with advance notice of pricing changes, enabling them to avoid using power during expensive, peak periods. In addition, AEP-East currently has traditional utility-sponsored Energy Efficiency programs in place in the East. Kentucky Power offers its customers the:

- Targeted Energy Efficiency (TEE) Program. The TEE program is designed to perform energy audits, provide energy education to all households, perform blower door tests and *install extensive weatherization and energy* conservation measures to low-income customers.
- Modified Energy Fitness Program. Available to consumers who use an average of 1,000 kWh or more a month; it includes weatherization measures, pipe wrap, and promotes the use of CFLs.
- Mobile Home Heat Pump Program. Includes incentives to upgrade mobile homes' HVAC systems with efficient heat pumps.
- Mobile Home New Construction Program. Encourages, through incentives, construction of mobile homes that utilize efficient heat pumps instead of conventional HVAC systems.

In Ohio and West Virginia, AEP has committed to spending a total of $2.75 million over three years for energy efficiency programs that primarily target low-income homes. The peak demand and energy impacts are not yet quantified.

The peak demand and annual energy conservation that results from the current East programs is summarized in **Exhibit 13**:

Exhibit 13: AEP-PJM Current DSM/EE

AEP East - Current DSM/EE		
	mw (summer)	mwh
Interruptible Contracts	485	-
Advanced Time of Day Pricing	129	-
Kentucky Programs	0.2	3,824
Total - East	614.2	3,824

8.3 Renewable Alternatives

Renewable generation alternatives represent those in which nontraditional (e.g. non-fossil) fuel sources that are either naturally occurring (wind, solar, or geothermal), or are sourced from a by-product or waste-product of another process (biomass or landfill gas), are utilized. Numerous renewable energy sources are under development or exist, but many sources like solar, geothermal, and tidal, are simply not economic options for AEP within our service territory, based on the current state of development for those technologies or for geographical reasons. Within the AEP service territory and without significant leaps in technology, biomass co-firing in coal power plants and wind plants are the primary options for economically (or realistically) generating electricity on a significant scale from renewable sources.

As highlighted in the Section 2 Overview, although effective in 25 states and the District of Columbia, no RPS exists today in any of the states in which AEP operates (excluding Texas, where AEP has limited generation and retail sales obligation). This being said, the notion of a potential Federal RPS is sufficiently tenable to warrant an evaluation of the merits of renewable generation in conjunction with this IRP process. Further, renewable energy sources have the ability to deliver attractive CO_2 benefits in a potentially carbon-constrained policy environment.

AEP's New Generation Development group evaluated a wide range of renewable technologies beginning in 2005, with updates in 2006 and 2007. The evaluations involved a multifaceted effort using input from many AEP groups. Technologies were evaluated on cost, location, feasibility, applicability to AEP's service territory, and commercial availability. After a high-level evaluation, economic screening was carried out considering each technology's estimated costs and effectiveness, to develop a levelized dollar-per-renewable-MWh cost. Costs and benefits considered in the screening included project capital and O&M costs; avoided capacity and energy costs; alternative fuel costs; alternative emission rates and associated allowance costs; and available federal or state production tax credits, if any. The levelized cost was used to rank the various technologies.

The renewable technologies ultimately screened include:

- biomass co-firing on existing coal-fired units
- separate injection of biomass on existing coal-fired units
- wind farms
  - evaluated separately for the East and West regions
  - with and without the federal production tax credit
- solar generation
- incremental hydroelectric production[7]
- landfill gas with microturbine[8]

- geothermal generation(8)
- generation from anaerobic digestion of waste material.(8)

Although some of the renewable technologies listed above could be economic, AEP is constrained from doing all of these projects as the energy sources are either geographically constrained in AEP service territory (e.g. geothermal) or are already saturated (landfill methane). Similarly, biomass co-firing is constrained by a supply of suitable fuel and/or transportation options anticipated to be in proximity to the host coal units evaluated. *Thus, the renewable resources available to be included in the Plan are not necessarily the least expensive options screened, but rather those that provide suitable economics and practicality.* A complete list of screened renewable technologies and their levelized costs is included in ***Appendix F***.

8.3.1 Wind

Wind is currently the fastest growing form of electricity generation in the world. Wind energy is generated by wind turbines with a range 1.0-to-2.5 MW, with a 1.5 MW turbine being the most common size used in commercial applications today. Typically, multiple wind turbines are grouped in rows or grids to develop a wind turbine power plant–or a wind farm–thus requiring only a single connection to the transmission system. Location of wind turbines at the proper site is particularly critical from the perspective of both the existing wind resource and its proximity to a transmission system with available capacity.

Ultimately, as production increases to match the significant increase in demand, the high capital costs of wind generation should begin to decline; currently, however, the cost of electricity from wind generation is not competitive within the AEP service territory without the accompanying subsidies, such as the federal production tax credit (PTC).

A drawback of wind is that it represents a sporadic or "intermittent" source of power in most non-coastal locales, with capacity factors ranging from 30-to-40%; thus, potentially, its life-cycle cost ($/MWh) is higher than more traditional generating sources, in spite of the zero fuel cost enjoyed by wind power. Another obstacle with wind power is that its most critical factors (i.e. speed and sustainability) are typically highest in very remote locations, and this forces the electricity to be transmitted long distances to load centers.

8.3.2 Biomass

Biomass is a term that includes organic waste products (sawdust or other wood waste), organic crops (switchgrass, poplar trees, willow trees, etc.), or biogas produced from organic materials. In the United States today, a large percentage of biomass power generation is based on wood-derived fuels, such as waste products from the pulp and paper industry and lumber mills. Biomass from agricultural wastes also plays a dominant role in providing fuels. These agricultural wastes include rice and nut hulls, fruit pits, poultry litter, and animal manure.

A relatively low-cost option to produce electricity by burning biomass is by co-firing it with coal in an existing boiler. In a typical biomass co-firing application, 5-15% of the generating unit's heat input is provided by biomass, and the remainder is provided by coal. Co-firing generally provides a lower-cost and lower-risk method of energy generation from biomass than building a dedicated biomass-to-energy power plant. In addition, a coal-fired power plant typically uses a more efficient steam cycle and consumes relatively less auxiliary power than a dedicated biomass plant, and thus generates more power from the same quantity of biomass.

Some drawbacks associated with biomass co-firing include reduced plant efficiencies due to lower energy content fuels, potential loss of fly ash sales, and potential fouling of SCR catalysts. Although these relatively minor obstacles can be mitigated through various means, the major obstacle to biomass co-firing is the transportability and resulting cost of the biomass fuel. Biomass has many competing demands, such as the pulp and paper, agriculture industries, as well as the emerging ethanol market, which can dramatically escalate the market price for the material along with the transportation of such a low energy-density fuel.

Another potential issue associated with biomass is the significant quantities of land dedicated and required to generate sufficient quantities of biomass. If, for example, AEP opts for a large amount of biomass co-firing at, say, 4,000 MW of existing coal units, this would require almost 600,000 acres of dedicated forest (assuming the forest is harvested in a sustainable manner) or require about 280,000 acres of switchgrass production from agricultural land. While this is a large amount of land, it still is only 2.7% of the total amount of harvested agricultural acreage in Ohio--totaling 10.4 million acres--and less than 0.1% of U.S. harvested acreage.

Biomass co-firing provides many valuable benefits and holds some promise for the AEP generating fleet, but the high fuel/transportation costs and the limited deployment potential on a heat-input basis could inhibit the near-term viability of the technology on a large scale.

Biomass co-firing is not a substitute for generation. Because it simply substitutes "carbon-neutral" fuel for fossil fuels, it does not eliminate the need for building generation as (peak) demand grows and assets are retired. However, if and when GHGs become regulated, biomass co-firing could become an economically viable way to reduce the CO_2 output of certain coal-fired plants.

8.3.3 Renewable Alternatives—Economic Screening Results

The described "no regrets" AEP renewable target of 5% of System energy (total East and West Zones) from renewable resources by 2020, working from a base of the current known AEP wind resources, and considering an additional 1,000 MW of nameplate wind resources committed to by the year 2010, the remaining renewable projects listed in **Exhibit 24** were included in the final 2007 IRP (AEP-East and West).

Exhibit 24: Technologies Included in the Final Plan

AEP System

Existing, Phase 1, and Phase 2 Renewables for 2007 IRP

Unit or Series		No. of Units	Year	Annual Energy (GWh)	Cumulative Annual Energy (GWh)
Existing Wind Contracts					
SW Mesa				109	109
Weatherford				569	678
Blue Canyon				581	1,259
Sleeping Bear				346	1,605
Assumed New Wind by 2010					
East - 850MW				2,442	4,047
West - 150MW				565	4,612
100 MW Wind Farm 1 SPP PTC	SPP PTC		2011	377	4,989
4 x 100MW wind SPP			2012-2015	1,507	6,495
Amos 1	Biomass Cofire	1	–	89	6,584
Big Sandy 2	Biomass Cofire	1	–	86	6,671
Tanners Creek 4	Separate Injection	1	2016	200	6,870
Rockport 1-2	Biomass Cofire	2	2016	353	7,223
Welsh 1	Biomass Cofire	1	–	79	7,302
Amos 1	Separate Injection	1	2017	407	7,709
Big Sandy 2	Separate Injection	1	2017	395	8,104
Stuart 1-4	Biomass Cofire	4	–	66	8,170
Stuart 1-4	Separate Injection	4	2018	302	8,472
Flint Creek 1	Biomass Cofire	1	2018	37	8,509
Mountaineer	Biomass Cofire	1	2019	139	8,648
Northeastern 3-4	Biomass Cofire	2	2019	132	8,780
Welsh 1	Separate Injection	1	2020	348	9,129
2 x 50 MW Wind Farm, PJM, PTC			2017-2018	289	9,418
2 x 50 MW Wind Farm, PJM, PTC			2019-2020	289	9,707

8.5 Demand Side Alternatives

8.5.1 Background

"Demand Side Management" (DSM) is a term that conveys different meanings to different people. In the strictest sense, it refers to the use of resources that defer the construction of generating assets. However, it has come to encompass, more broadly, the spectrum of peak demand management and energy efficiency (EE) measures. The distinction between peak demand reduction and energy efficiency is important, as the solutions for accomplishing each objective are typically different.

8.5.2 Peak Demand Reduction

Peak demand, measured in kilowatts (kW), can be thought of as the amount of power used at the time of maximum power usage. In AEP's respective East (PJM) and West (SPP) zones, this maximum (peak demand) is likely to occur on the hottest summer weekday of the year, in the late afternoon. This happens as a result of the near-simultaneous use of air conditioning by the majority of customers, as well as the normal use of other appliances and (industrial) machinery. At all other times during the day, and throughout the year, the use of power is less.

As peak demand grows with the economy and population, new capacity must ultimately be built. To defer construction of new power plants, the amount of power consumed at the peak must be reduced. This can be addressed several ways via both "active" and "passive" measures:

- *Interruptible loads*. This refers to a contractual agreement with the utility and a heavy consumer of power, typically an industrial customer. In return for reduced rates, an industrial customer allows the utility to "interrupt" or turn off his power during peak periods, freeing up that capacity for other consumers.
- *Direct load control*. Very much like an (industrial) interruptible load, but accomplished with many more, smaller, individual loads. Commercial and residential customers, in exchange for monthly credits, allow the utility to (remotely) deactivate discrete appliances, typically air conditioners, hot water heaters, or pool pumps during periods of peak demand.
- *Time of Day (TOD) rates*. Offers a customer different rates for power at different times during the day. During periods of peak demand, power would be relatively more expensive, encouraging less consumption.
- *Energy Efficiency measures*. If the appliances that are in use during peak periods use less energy to accomplish the same task, peak energy requirements will likewise be less.

What may be apparent is that, with the exception of Energy Efficiency measures, the amount of power consumed is not typically reduced. Less power is consumed at the peak, but to accomplish the same amount of work, that power will be consumed at some point during the day. Instead of the air conditioner operating at four o'clock, it will come on at six to get the house cooled down. If rates encourage someone to avoid running their dishwasher at four, they will run it at some other point in the day.

8.5.3 Energy Efficiency (EE)

EE measures save money for customers billed on a "per kilowatt-hour" usage basis. The trade-off is the reduced utility bill for any up-front investment in an appliance/equipment modification, upgrade, or new technology. If the consumer feels that the new technology is a viable substitute and will pay him back in the form of reduced bills over an acceptable period, he will adopt it.

EE measures will, in all cases, reduce the amount of energy consumed. They will accomplish the same task for less energy. However, EE may have limited effectiveness at the time of peak demand and, in fact, that is often the case.

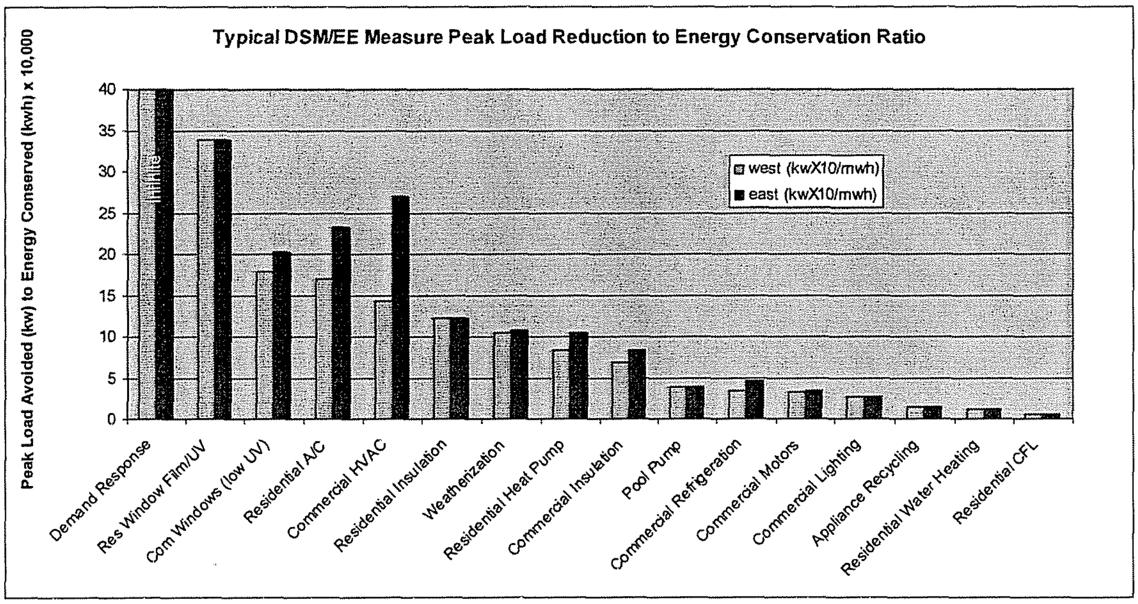
Some examples will illustrate this point. First, a more efficient air conditioner will likely reduce consumption at the peak; the same amount of cool air is being generated with less energy. A more efficient refrigerator will have a lesser impact on the peak as the chance of it running consistently at the peak time ("peak coincidence") is less than that of the air conditioner. A compact fluorescent light bulb (CFL), while using considerably less energy to accomplish the same task, has low coincidence (the peak occurs during the daylight hours), and outdoor lighting has coincidence of zero (for the same reason).

Conversely, the efficiency measures that have the greatest effectiveness at the peak save the least energy (in very broad terms) because they are seasonal. This is less true in warmer climates where the summer season is longer; an efficient air conditioner will conserve more energy in Oklahoma than in Michigan (note the ratio of peak savings to energy conservation differences for air conditioning measures between AEP's East and West service territories in the following chart).

Exhibit 26 shows the relationship of typical measures on the continuum of "Demand Side Management" to "Energy Efficiency." Demand response measures, which interrupt load at the peak and have no energy savings, are at the far left. Measures with larger energy efficiency components–with little corresponding peak demand reduction–are to the right. The y-axis is merely a ratio of demand reduction (kW) to energy conservation (kWh), adjusted for scale.

Notably, the air conditioning measures ("Residential AC" and "Commercial HVAC") show distinct differences by region. Because air conditioners are likely to be on during the peak (high coincidence), there is a significant peak demand reduction component. In the West, where the cooling season is longer, there is a larger energy conservation component. Thus, the ratio of demand reduction to energy conservation is *lower* for these measures in the West, relative to the East.

Exhibit 26: Typical DSM/EE Measure Peak Load Reduction-to-Energy Conservation Ratio



9.0 Evaluating DSM/EE Impacts for the 2007 IRP

Quantifying the DSM/EE impact on peak demand and energy consumption into the future is a challenge for several reasons. First, it involves gauging future consumer appetite for DSM/EE technologies, specifically, and consumer behavior in general. Second, a large volume of very specific customer data is needed to precisely quantify the potential. And not least, the experience of past and present DSM/EE program efforts should be incorporated.

To determine, for 2007 IRP planning purposes, an amount of DSM/EE that will occur during the evaluation period, the following methodology was employed:

- Incorporate all current DSM/EE programs.

- Estimate a level of measure adoption that will occur naturally as a function of customer demographics, awareness and sophistication, consumer power rates, and technology costs and effectiveness.
- Further estimate a level of measure adoption, a subset of the above, that can be accelerated into the planning horizon, given a low-cost informational campaign
- Evaluate currently available technologies for cost-effectiveness within the AEP service territory. Target these technologies for utility-sponsored DSM/EE programs.

9.1 Evaluation of Current Technologies

AEP engaged R.J. Rudden and Associates to provide a catalogue of available DSM/EE technologies, their cost and effects on peak demand, and energy consumption by a variety of end-uses. The information, culled from publicly available sources, primarily the California "DEER" (Database for Energy Efficient Resources) system, was "fitted" to the AEP service territory. This was done through linear regression of relevant variables such as heating degree-days, cooling degree-days, peak temperature days, and ground water temperature. The technologies and end uses included for evaluation are included in ***Appendix G.***

9.2 The Consumer

Most customers (primarily Residential and Commercial), absent any incentives, credits, or altruism, benefit only from a reduced monthly power bill. Thus, energy efficiency, not peak energy reduction, matters to him in the short term. The higher their rates, the more motivated they are to reduce consumption. Measures that provide no, or limited, annual *energy* conservation (and reduced bills) will not be adopted without incentives or credits, often from the utility. Measures that save energy, regardless of whether that occurs at the time of peak demand, will result in lower bills, and require no, or limited, incentives or credits to be adopted.

Geography also plays a role. An efficient hot water heater or low-flow shower head may save more energy in climates where the groundwater is cooler. However, if electricity rates are lower, it is possible that this measure is more attractive where it saves less energy (where groundwater is warmer). As **Exhibit 27** demonstrates, using the same technology, a consumer who saves more energy in Michigan (I&M) will save less on his bill than a consumer in the Columbus Southern Power (Ohio) service area or the Public Service of Oklahoma area.

Exhibit 27: Example of Geographic Differences in DSM/EE Effectiveness and Consumer Preferences

Low Flow Showerhead					
	Annual Energy Savings (kwh)	Residential Rates ($/kwh)	Annual Bill Savings ($)	Annualized Device Cost Borne by Participant ($)	Participant Score
Columbus Southern Power	145.83	0.087	12.69	5.88	2.16
Public Service of Oklahoma	119.67	0.084	10.06	5.88	1.71
I&M - Michigan	149.88	0.062	9.23	5.88	1.57
SWEPCo - Arkansas	112.92	0.077	8.67	5.88	1.47
Wheeling Power	128.80	0.057	7.30	5.88	1.24

The ratio of benefits to costs, from the consumer's perspective, is called the Participant Score. The Participant Score can be very telling as to whether or not a particular DSM/EE measure will gain widespread acceptance. As benefits (reduced annual electricity bills and any incentives) begin to outweigh costs (the annualized cost of purchasing and installing the device or upgrade), more consumers will adopt it. Conversely, if the measure does not produce significant bill savings for the consumer, it will take larger incentives to achieve widespread adoption.

It is the consumer of power who has the ultimate say in how much energy is consumed and when it is consumed. For precisely the reason that everyone wants to consume energy at times of peak demand, it is unpopular–and thus expensive–to reduce consumption at that time. Energy efficiency–less expensive and of more immediate benefit to consumers–may do little to reduce peak demand.

Thus, while the two objectives of peak load reduction and energy efficiency are not mutually exclusive, they may not be attained through the same means. An energy efficiency program will, in all likelihood, not avoid or defer capacity additions. A demand response program will not, on balance, conserve energy.

9.3 Theoretical Market Potential

Using data from customer surveys, informed estimates from R.J. Rudden & Assoc., and experience, an estimate of market potential for each DSM/EE measure/technology assessed was formed as of a chosen "baseline" DSM/EE year of 2010. The aggregation of those measures and markets yields a DSM/EE market potential (as represented in Exhibit 27).

Exhibit 28: AEP East – Theoretical Market Potential DSM/EE

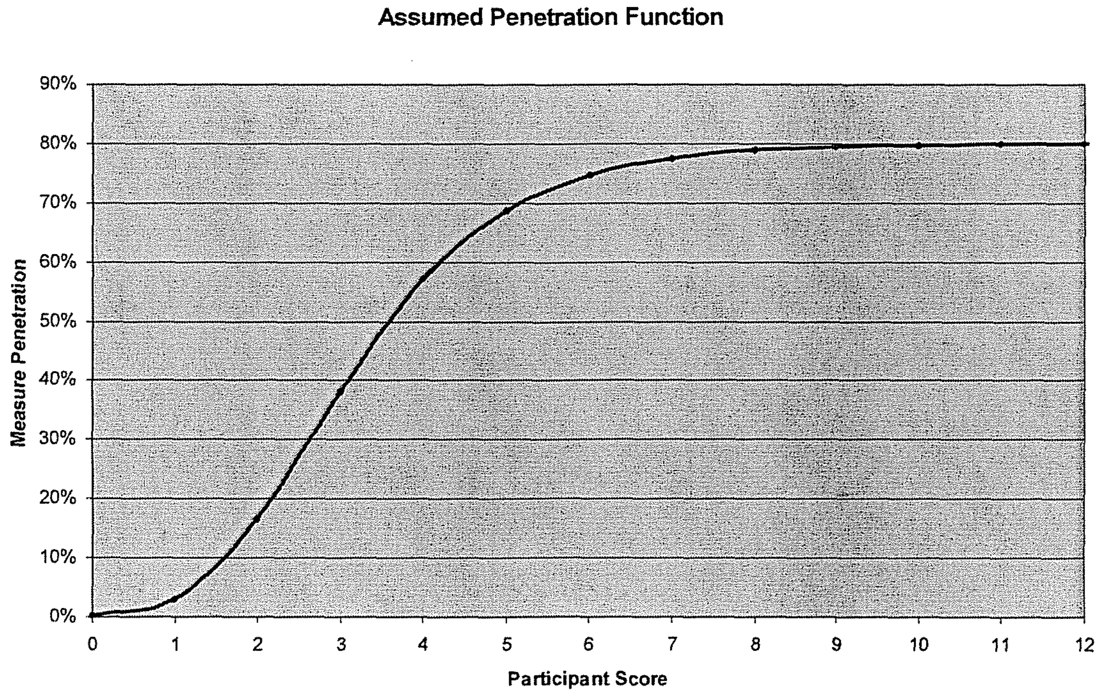
AEP East - Market Potential Evaluated DSM/EE		
	MW	MWH
Market Potential	3,460	9,763,000

It is important to stress that these numbers reflect a *100% adoption of all measures by all applicable customers*. Obviously, this will not be attained, as not every consumer, regardless of whether or not economic benefits exist, will embrace *every*, or even *any*, technology.

It must be further recognized that, in the face of economic benefit to do so, consumers will adopt energy efficiency on their own. The remainder of the market, up to some limit, will adopt when the benefits are fully understood or the benefits become more favorable. Promoting the full benefits of DSM/EE technologies is a low-cost way to accelerate their adoption. Utility-offered incentives, tax incentives, or (avoided) rising energy costs all increase the benefits (relative to the costs) of DSM/EE measures.

By definition, the DSM/EE that actually happens is far less than the market potential. To estimate how much DSM/EE might practically be affected, some gauge of consumer preferences and product adoption was necessary. **Exhibit 29** depicts an "S-curve," which is commonly used in explaining consumer demand for new products. The phenomenon of "early adopters"–those who will purchase a (DSM/EE) technology at any price (low Participant Score)–transitions to the majority of consumers who will adopt faster as the price (savings) increases, and finally to the "hold outs," who will *never* adopt the technology. For that reason, an upper limit of 80% product adoption, or *penetration*, was assumed.

Exhibit 29: Assumed Penetration Function



Notes about the assumed consumer demand function:

- *The curve shape is representative of consumer demand functions that are typically developed through research and empirical testing.*
- *The curve describes minimal participation (penetration) where a measure is not economically advantageous. As the measure gains economic viability, as the costs are reduced, or the savings are increased, participation increases. Eventually, participation becomes incrementally less, even as the economic benefit to the consumer increases.*
- *How well this curve explains the future adoption of DSM/EE measures remains to be seen. Certainly, adoption will be greater the more advantageous (economical) it is to the consumer. As programs are developed and implemented, the intelligence gained around*

consumer preferences in the AEP service territory will serve to redraw this curve in subsequent analyses.

Given this function for consumer product adoption, the current residential and commercial rates in the AEP service territories, the efficacy of the various technologies given the regional characteristics, and market potential, an estimation of "naturally occurring" DSM/EE in or around a baseline year of 2010 can be made as represented in **Exhibit 30**.

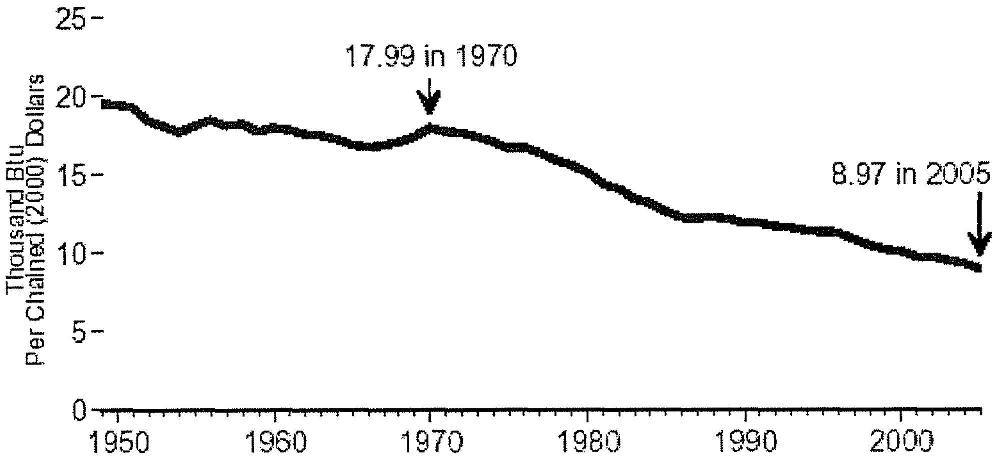
Exhibit 30: AEP East – Naturally Occurring DSM/EE

AEP East - Naturally Occurring Evaluated DSM/EE		
	MW	MWH
Naturally Occurring	470	2,201,000

The assumption is that this level of naturally occurring DSM/EE is a subset of the total efficiency that may or may not be implicit in the (SAE) Load Forecast. It is difficult to say this with certainty, because one is measuring energy that was not consumed. However, historical trends indicate that DSM/EE does occur without utility programs and can be thought of as simply the purchase of a CFL from a home improvement store without any coupons or rebates–an everyday occurrence across America. To reiterate a point made earlier, it happens more often where utility rates are higher.

From **Exhibit 31**, one can extract an annual decline in energy usage of all thermal sources/fuels of 2.0% for each unit of GDP nationally since 1970.

Exhibit 31: Energy Use per Real Dollar of Gross Domestic Product



Source: EIA – Annual Energy Review 2005

Whereas, the 2,201 GWH of AEP-East energy conservation assumed to occur naturally (reflected in Exhibit 30), as it relates to the evaluated DSM/EE measures, represents annual conservation of 0.3% from 2005 to 2010. There are several reasons why this is less than this 1.0-2.0% proxy:

- The evaluated measures represent a subset of the universe of EE measures available to consumers.
- Electricity rates in the AEP-East zone generally lag the national average.

- Some slowing of the percentage gains in efficiency would be expected over time.
- Growth in the AEP-East zone is less than the U.S. GDP growth from 1970-2005.

Additionally, there are many sources of error that make this number less than precise. The central point, however, is that, given the set of evaluated measures, it is not unreasonable to expect that some amount will occur naturally, and that the amount then assumed in this IRP assessment is conservative.

9.4 Effect of an Informational Campaign

Gauging the effect of informational programs is likewise subject to objective evaluations. Borrowing from some research in behavioral science,(9) one can model the effect of "word-of-mouth." The concept is that as more people adopt a technology, the rate of adoption accelerates as the product gains acceptance, then decays as all who wish to adopt it, do. As reflected on **Exhibit 32**, the informational campaign has the effect of increasing the level of current technology adoption from a hypothetical 3% to 10%. This increase in technology adoption then has the effect of accelerating the word-of-mouth process.

Exhibit 32: Information Can "jump-Start" the "Word-of-Mouth" Product Adoption Phenomenon

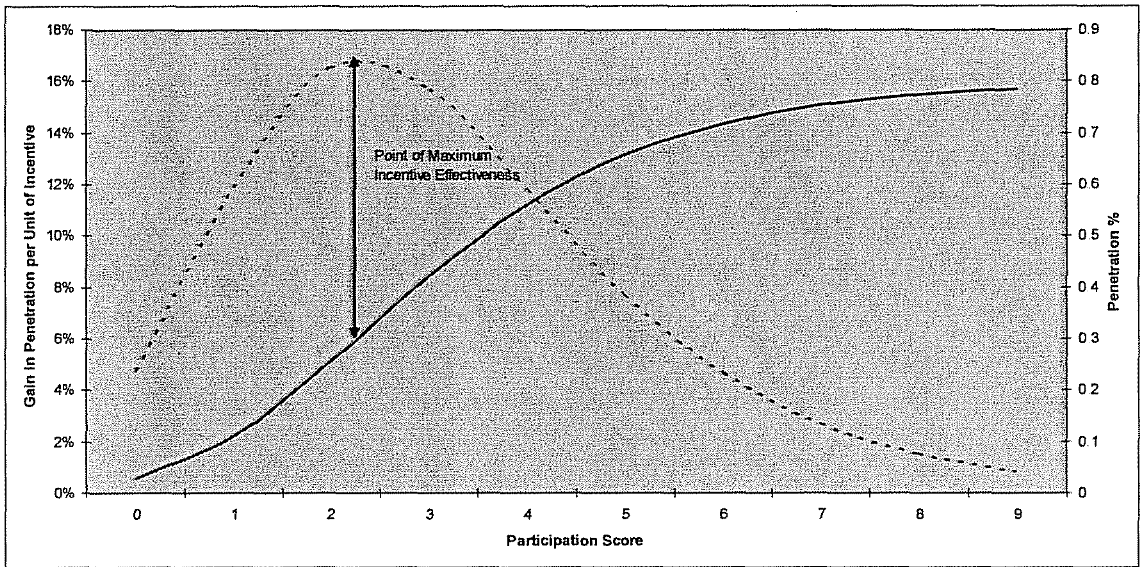


Exhibit 33 shows the estimated AEP-East DSM/EE that would occur naturally over time, and could be "pulled forward" from future periods *outside* of the "normal load and demand forecast window:"

Exhibit 33: AEP East – Accelerated DSM/EE (by 2010)

AEP East - Accelerated DSM/EE		
	MW	MWH
Informational Campaign	157	732,933

Because this number cannot be characterized as exact, it may be helpful to examine the consequences of over or underestimating the amount of DSM/EE that can be put into effect with some form of promotional or informational campaign.

If the amount is overestimated, the DSM/EE that is potentially available through a utility-sponsored DSM program is understated, and vice-versa. But the total amount of DSM/EE remains that which is economical for the consumer and the utility. What would be affected is the sharing of the cost of implementing the DSM/EE between the utility and the consumer. If more consumers can be convinced to adopt a DSM/EE measure through a low-cost informational campaign (i.e. the amount of DSM/EE garnered from an informational campaign was understated), they will bear more of the cost. If not (i.e. the amount of DSM/EE from an informational campaign was overstated), the utility must ply the consumer with incentives, and the utility will bear more of the cost. The absolute timing of the impacts would also vary as would total program costs, but not to a level that is material.

9.5 Effect of Utility-Sponsored DSM/EE Programs

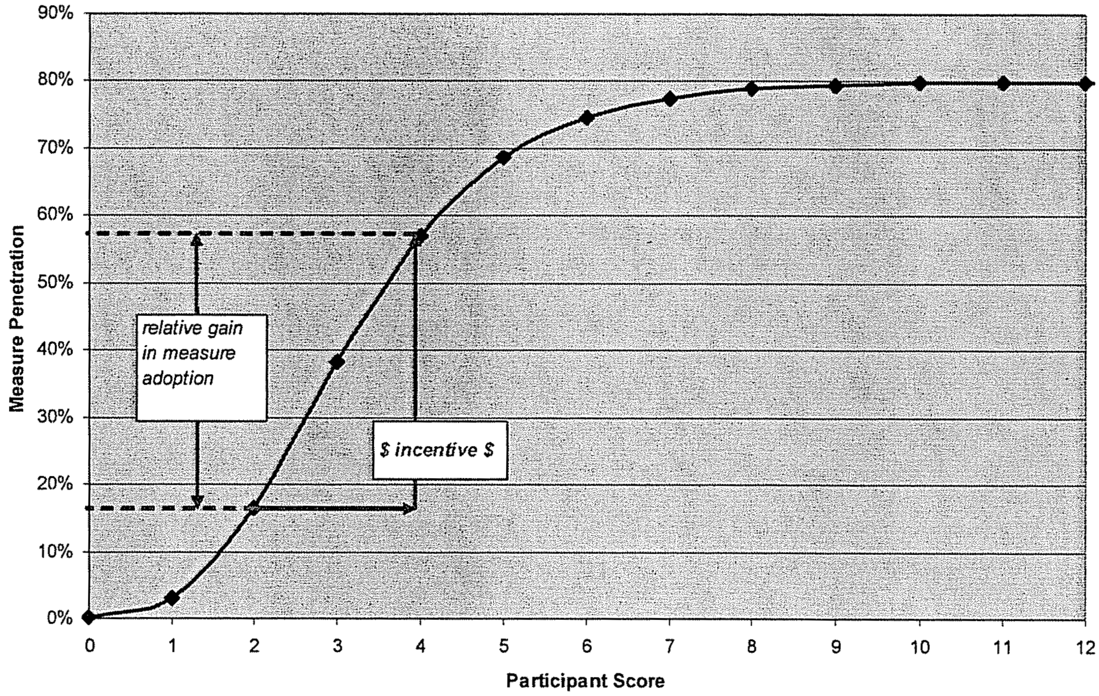
Lastly, for the technologies that require additional consumer benefits to increase adoption, utility sponsored incentives were calculated such that the addition of the incentive and associated costs did not reduce the economic viability of the technology below one of two thresholds, as measured by either the Ratepayer Impact Measure (RIM) test or Total Resource Cost (TRC) test.

As depicted in **Exhibit 34**, the addition of incentives, whether in form of coupons, rebates, or "buy downs"–which are subsidies made at the wholesale level to reduce the price at the retail level–has the effect of increasing the participant score, which correspondingly increases the penetration.

However, as incentives are added, the economic scores of the measures decline in the following way:

- The RIM test is directly reduced with incentives by the amount of the incentive and a corresponding administrative cost, assumed to be 15% of the incentive.
- The TRC test is only reduced by the amount of the administrative costs.

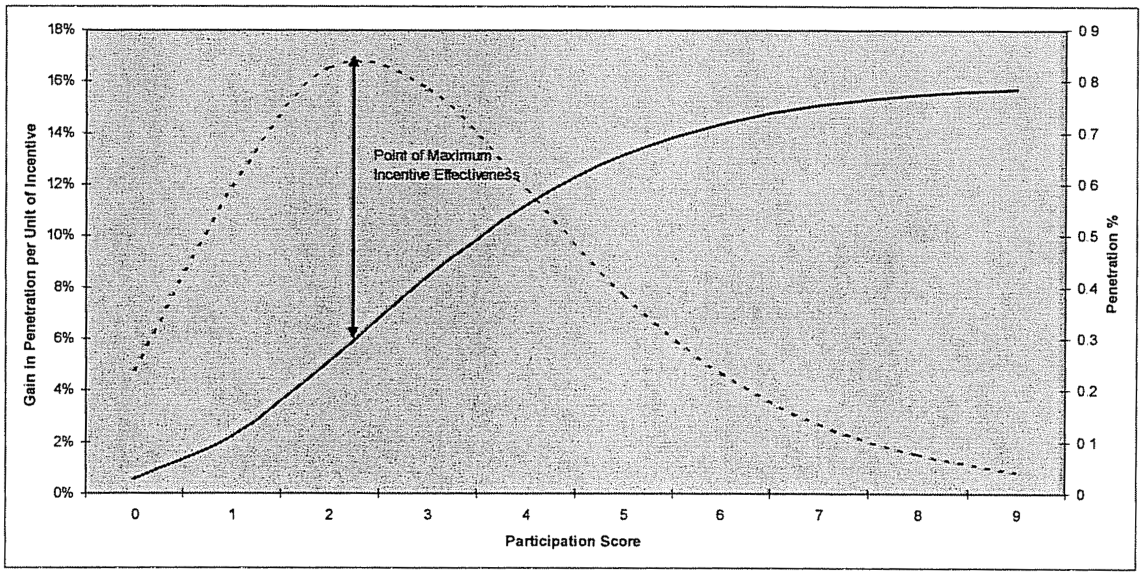
Exhibit 34: Illustration of Incentive Effect on Measure Adoption



9.5.1 Optimizing the Incentive Level

Since one could add incentive to the point that the utility, in effect, buys the technology for the consumer, it was necessary to estimate the point where *the greatest gain in product adoption is realized for the least amount of incentive*. As proxied on **Exhibit 35**, this is accomplished by determining the point of the function where the greatest increase in penetration occurs for a corresponding increase in participation score. This point occurs at a participation score of approximately 2.3. For the sake of measure-specific economic screening, this was rounded up to a participation score of **3.0.**

Exhibit 35: Penetration Function and Point of Maximum Effectiveness



Thus, if a measure in the market potential that was not deemed to be "naturally occurring" or was not included in the DSM/EE achieved through an informational campaign, but still passed one of the economic criteria (RIM or TRC) with the addition of incentive added to achieve 3.0 participation, that measure was included in the subsequent "utility-sponsored" DSM/EE bucket.

9.5.2 Ratepayer Impact Measure (RIM)

This measure of economic viability of a DSM/EE measure is a ratio of benefits to costs from the view of a nonparticipant; it is sometimes referred to as the "nonparticipant's test." It measures whether, as a result of a utility-sponsored program, the utility's rates will increase, thus economically injuring a nonparticipant. The spreading of lower costs over fewer kilowatt-hours can have the effect of increasing, or decreasing rates (per kilowatt hour).

The more effective a measure is at reducing *energy* consumption relative to mitigating the need for additional capacity, the less likely it will pass RIM. Similarly, if a measure passes RIM, it likely reduces the need for additional capacity more than it reduces energy consumption.

RIM benefits include:

- Avoided cost of capacity (the marginal cost of capacity).
- Avoided cost of production (the marginal cost of production) and associated transmission and distribution, including losses.

RIM Costs include:

- Utility program costs, including any incentives paid to participants.
- Lost revenues that must be recovered to meet a fixed revenue requirement.

9.5.3 Total Resource Cost (TRC) Test

This measure has identical benefits as the RIM test but varies in the composition of the costs.

Costs include:

- Utility program costs, <u>excluding</u> any incentive paid to the participants.
- Participant costs (largely the cost of purchasing the measure).

9.6 Discussion and Conclusion

Using each of the two tests as criteria for developing DSM/EE programs will yield different results. If the philosophy of the ratemaking body is not to condone subsidization of consumers who choose to participate in a utility-sponsored DSM/EE offering by those who do not participate, then the RIM test is appropriate. Nonparticipants might not participate for a variety of reasons, however, including an inability to do so. For example, a ratepayer who has already purchased efficient appliances and/or lives in a more thermally efficient home would likely not be able to take advantage of a typical utility-sponsored initiative.

The TRC criterion will allow for subsidization as it seeks only to establish measures that are cheaper alternatives to producing more power and/or building incremental capacity.

Other differences between the two tests include:

- *Sensitivity to rates.* The RIM test results can vary by jurisdiction as a function of rates. The TRC test is not affected by rates.
- *Sensitivity to geography.* Increased effectiveness of conservation measures (e.g. more efficient water heaters conserve more energy where groundwater is cooler) will improve TRC scores, but can degrade RIM scores as the value of lost revenues (potentially) outpaces the benefits of avoided costs.

For this 2007 IRP cycle, the ultimate, incremental, utility-sponsored DSM/EE programs were selected by their TRC scores. Not only is it consistent with emerging AEP Policy, it acknowledges a desire by national and state legislative bodies to aggressively pursue energy conservation and peak demand reduction and is consistent with AEP Policy. The TRC test more effectively subscribes to energy conservation measures, just as the "lost revenues" component of the RIM test effectively limits DSM/EE efforts to measures that have a higher peak demand savings to energy conservation ratio.

Regardless of the test employed to evaluate measures for possible inclusion in a utility-sponsored program or targeted informational campaign, full regulatory recovery of all program/measure costs, *including* lost revenues, will initially be pursued.

9.7 Profile of DSM/EE included in the 2007 IRP

The amount of DSM/EE included in this Plan is significantly higher than what is currently offered or what has been forecasted in recent plans. There are a few reasons why this assumption is valid:

- Rising energy costs will increase demand for energy efficiency measures. As public awareness and acceptance of available technologies grows, whether through informational campaigns or word-of-mouth, DSM/EE will grow, even in the absence of utility-sponsored programs and incentives.
- Increased awareness and acceptance of the link between global warming and the consumption of fossil fuels will drive increased adoption of conservation measures, *independent* of economic benefit.
- Increased emphasis of national and state legislative bodies on achieving conservation.

The DSM/EE incorporated in this IRP, although constructed with considerable detail, does not yet reflect actual programs, unless noted. As the mechanism for regulatory cost recovery and the appetite for utility-sponsored DSM/EE is formalized through the legislative and ratemaking processes in the various jurisdictions in which AEP operates, the amount and type of DSM programs will likely change.

The following **Exhibits (36-39)** summarize the AEP-East DSM/EE assumptions for the 2007 IRP. Note that each has been identified in relative "tranches" beginning immediately (2007) and then advancing in five-year intervals through the planning horizon beginning in 2010.

Consequently, the DSM/EE resources modeled in this process should be viewed as a placeholder for potential future impacts that would include, as sequentially described in this report:

- All naturally occurring DSM/EE that is assumed to be implicit in the long-term load forecast.
- Incremental DSM/EE that is estimated to be accelerated into the forecast period through the use of a low-cost informational campaign.
- Incremental DSM/EE that, after incentives necessary to obtain a Participant Score ≥ 3, passes the TRC test (TRC$\geq$1).

Note: All of the above components will eventually be folded into future load forecasts as discrete components as information is gained and state/jurisdictional programs become finalized and implemented.

Exhibit 36: AEP East – Energy Efficiency/Conservation Assumptions for the Spring 2007 IRP

Energy Conserved (MWh)				
	2007	2010	2015	2020
Informational Campaign		732,933	732,933	732,933
Utility Sponsored DSM/EE	-	21,964	113,931	288,215
Subtotal	-	754,897	846,864	1,021,148
plus:				
Current Utility Sponsored DSM/EE	3,824	3,824	3,824	3,824
Total - All Energy Efficiency/Conservation (MWh)	3,824	758,721	850,688	1,024,972

Exhibit 37: AEP East – Energy Conservation

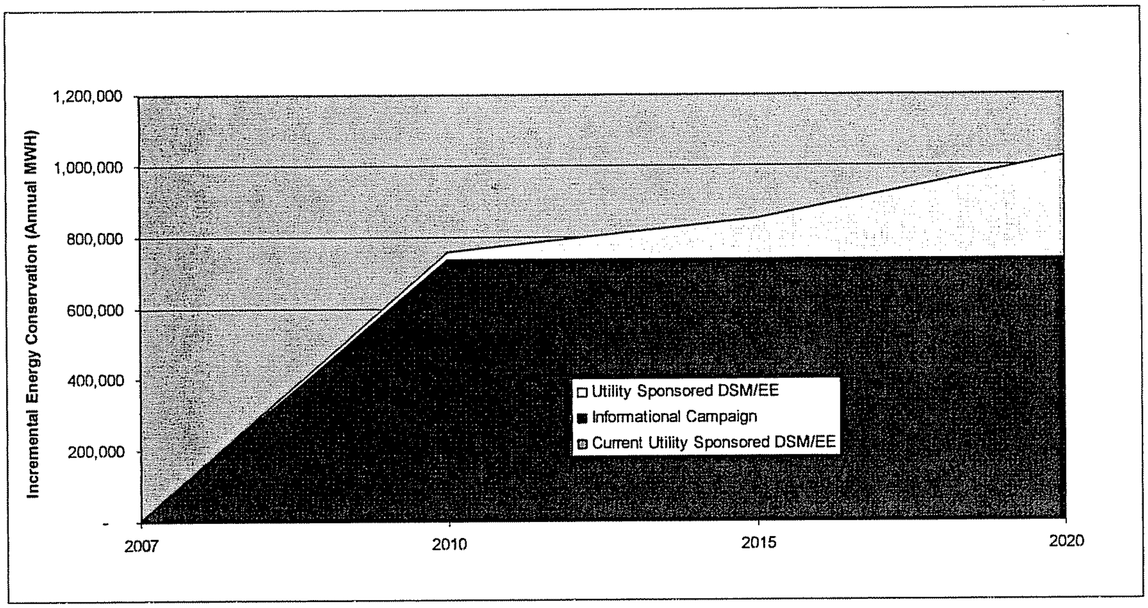
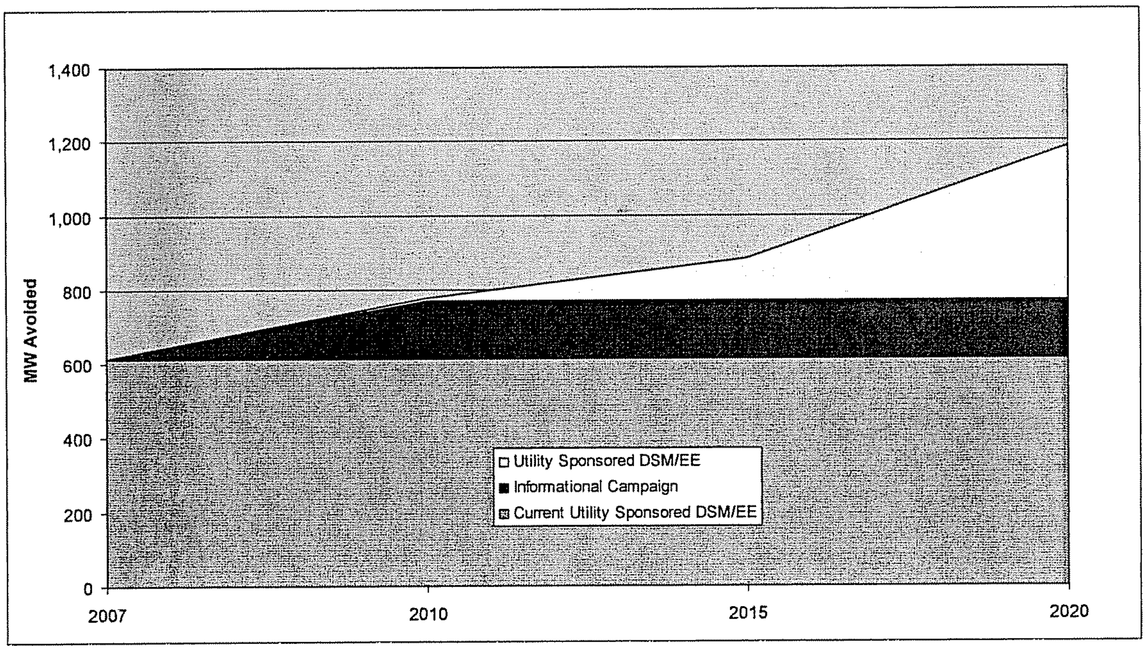


Exhibit 38: AEP East – Demand Reduction Assumptions for the Spring 2007 IRP

Energy Conserved (mwh)				
	2007	2010	2015	2020
Current Utility Sponsored DSM/EE	3,824	3,824	3,824	3,824
Informational Campaign		732,933	732,933	732,933
Subtotal	3,824	736,757	736,757	736,757
Utility Sponsored DSM/EE	-	21,964	113,931	288,215
Total	3,824	758,721	850,688	1,024,972

Exhibit 39: AEP East – Demand Reduction



Appendix F: Economically Screened Renewable Alternatives

Economically Screened Renewable Alternatives		Life-cycle Cost vs. Avoided Costs (Levelized $/MWh)
Landfill Gas 800kW Microturbine *	Gas	-27.99
Incremental Hydro *	Hydro	-16.59
Geothermal *	Geothermal	-4.37
Wind Farm SPP PTC	SPP w/PTC	5.43
Amos 3	Biomass Cofire	12.02
Amos 1 or 2	Biomass Cofire	12.17
Big Sandy 2	Biomass Cofire	12.74
Tanners Creek 4	Separate Injection	13.71
Beckjord 6	Separate Injection	14.05
Rockport	Biomass Cofire	18.80
Welsh	Biomass Cofire	19.20
Amos 1 or 2	Separate Injection	19.32 (a)
Amos 3	Separate Injection	19.96 (a)
Big Sandy 2	Separate Injection	20.15 (a)
Oklaunion 1	Biomass Cofire	21.70
Stuart	Biomass Cofire	23.57
Muskingum River 5	Biomass Cofire	23.79
Stuart	Separate Injection	24.06 (a)
Flint Creek 1	Biomass Cofire	25.89
Mountaineer	Biomass Cofire	25.93
Big Sandy 1	Biomass Cofire	26.59
Northeastern 3 or 4	Biomass Cofire	27.08
Cardinal 1	Biomass Cofire	27.13
Welsh	Separate Injection	27.22 (a)
Gavin	Biomass Cofire	27.36
Zimmer	Biomass Cofire	27.77
Rockport	Separate Injection	27.84 (a)
Conesville 6	Biomass Cofire	28.02
Conesville 5	Biomass Cofire	28.27
Mitchell	Biomass Cofire	28.71
Wind Farm SPP, no PTC	SPP no PTC	29.52
Oklaunion 1	Separate Injection	29.85 (a)
Muskingum River 5	Separate Injection	30.63 (a)
Beckjord 6	Biomass Cofire	31.21 (a)
Flint Creek 1	Separate Injection	32.05 (a)
Dolet Hills 1	Biomass Cofire	32.74
Conesville 4	Biomass Cofire	32.85
Zimmer	Separate Injection	33.18 (a)
Pirkey 1	Biomass Cofire	33.42
Mountaineer	Separate Injection	34.47 (a)
Northeastern 3 or 4	Separate Injection	34.64 (a)
Conesville 6	Separate Injection	34.87 (a)
Conesville 5	Separate Injection	35.32 (a)
Wind Farm, PJM PTC	PJM w/PTC	35.63

Note: (a) the cost of a second technology at a unit is incremental, that is, additional renewable energy divided by incremental cost.

Kentucky Power Company
DSM Impact Reflected in
2007 Integrated Resource Plan

Kentucky

	2010	2015	2020	Total in IRP
Energy (MWh)	30,044	3,660	6,936	40,640
Demand (MW)	6.3	4.2	11.9	22.4