The 2002 Entergy System Resource Plan

Electric Power Needs and Resource Options 2002 - 2011

Chapter
1

Summary

This report documents the preliminary results of the Entergy System's[1] 2002 resource planning process. In particular, this process seeks to assess whether the recent strategy of meeting incremental resource needs with short-term wholesale power purchases remains the most economical alternative for reliably meeting the energy needs of the Operating Companies' customers in light of the other long-term resource alternatives that are available. Based on an analysis that considers the uncertainties associated with the level of future resource needs and the relative costs of a wide variety of strategies for meeting those future resource needs, the System has determined that, in the near-term, the System's recent strategy – meeting near-term resource needs with short term purchases of capacity and energy products – continues to be the most appropriate near term resource plan.

In the near term, the System expects that it will need to acquire approximately to MW of resources for the Summer of 2002. This need will be met with a combination of short-term energy purchases (e.g., three month liquidated damages or unit contingent energy purchases), capacity products (e.g., call options), and mid-term energy purchases (e.g., 12 to 36 month contracts).

The System's 2002 resource planning process also considered longer-term resource needs, focusing on minimizing long-term costs and evaluating the implications of long-term resource acquisitions on the short-term resource plan. The System concluded that there is a very high degree of uncertainty regarding various scenarios associated with the load that the System could reasonably anticipate serving over the next ten years. This demand uncertainty results in a large variation in potential supply requirements over the next ten years, ranging from incremental resource needs to as much as MW. This demand uncertainty results from the potential load losses due to cogeneration and the prospects for full or partial retail access in Texas, Arkansas and Louisiana. The long-term resource plan evaluated the costs (i.e., the net present value of the revenue requirements stream) for a wide range of alternatives, including purchased power alternatives presented to the System as the result of a solicitation for Requests for Proposal ("RFP") for long-term (10 year) power purchases; construction of new greenfield coal plants, simple cycle combustion turbines, and combined cycle combustion turbines; uprating the System's nuclear power plants; and repowering existing System generating units. This evaluation indicated that the most cost-effective long-term resource alternatives available to the System were nuclear uprates and repowering.

The System is continuing to evaluate the nuclear uprate projects that have been identified as cost-effective. This continued evaluation includes more detailed analysis as to the technical feasibility of these projects, more detailed cost estimates, and an assessment of the amount of time that would be required to implement the uprates and how any uprating project should be consolidated into the maintenance schedule for the plants so as not to conflict with mandatory safety-related projects. Should this further analysis continue to show that these projects remain cost-effective, they will be implemented.

[1] The Entergy System consists of five retail Operating Companies: Entergy Arkansas, Inc. ("EAI"), Entergy Gulf States, Inc. ("EGS"), Entergy Louisiana, Inc. ("ELI"), Entergy Mississippi, Inc. ("EMI"), and Entergy New Orleans, Inc. ("ENO").

The System also determined that repowering ENO's Michoud 2 generating unit would be an economically-attractive resource alternative. However, the costs of immediate repowering still exceed the costs of meeting future resource needs with short-term purchased power alternatives.

Chapter
2

Background

Objective of the Plan

The objective of this resource plan is to identify the resource options and strategies that enhance the Companies' ability to meet customer needs at competitive prices and increase their flexibility to meet load while still considering industry structural uncertainty. As electricity markets continue to become more competitive and price sensitive, objectives that disregard competition – at either the wholesale or retail level -- are inappropriate and unsustainable.

The Electric Utility Environment

The Entergy System's 1995 Least Cost Integrated Resource Plan ("LCIRP") noted that significant changes were taking place in the electric utility industry. The experiences over the last seven years emphatically confirm the foresight of that observation. The 1995 LCIRP observed that the wholesale electric market was already very competitive, and concluded that the most reasonable course of action for the System to take to meet its future resource needs economically and reliably was to Return-to-Service the units it had placed in Extended Reserve Shutdown (ERS) during the 1980's. The System has returned to service all of the economically viable units and now must supply its incremental resource needs from other sources.

Several significant events have occurred since the 1995 LCIRP was prepared. The Federal Energy Regulatory Commission ("FERC") has continued to push forward to increase the competitiveness of the wholesale electric markets, primarily by ensuring that all generators of electricity have open access to the transmission grid. One consequence of the FERC's activities has been a boom in the amount of electricity produced by non-utility generators, including cogenerators (also known as Qualifying Facilities or "QFs") and independent power producers ("IPPs") who have build new generating plants as merchant facilities to sell power into the wholesale marketplace. A large amount of non-utility generation has been built, or is being built, in the Entergy System region and the surrounding area. Henwood Energy Services Inc. forecasts that between 1999-2002 over 20,000 MW of new generating capacity is to be completed in the SPP-SERC region. The emergence of these varying forms and levels of competition has fundamentally changed the way the utility industry must plan and operate in the future.

State and Local Regulatory Issues

Retail Open Access

Since the 1995 LCIRP was prepared, there has been an ebb and flow of activity regarding the implementation of competition at the retail level across the Entergy System. The status of retail open access in each of the jurisdictions in which the Operating Companies do business is summarized below.

Arkansas

In 1999, the Arkansas General Assembly passed legislation that was to implement retail choice in the state of Arkansas (in which EAI operates) by January 1, 2002. However, that legislation allowed the Arkansas Public Service Commission ("APSC") some flexibility in implementing retail choice. After much discussion, the APSC has delayed the implementation of retail choice in Arkansas until September 2003, and has further recommended that the General Assembly repeal the legislation enabling retail choice, or significantly delay its implementation.

Louisiana

The Louisiana Public Service Commission ("LPSC") is currently considering a number of options regarding the implementation of retail choice in Louisiana. It does not seem likely that the LPSC will implement a retail choice for all customers in the near future. However, the LPSC has been considering whether to allow limited open access to select groups of customers (generally believed to be large industrial customers), with no concomitant requirement that the incumbent utilities (including EGS and ELI) divest their generating assets.

Mississippi

The Mississippi Public Service Commission and the state legislature have reviewed deregulation issues and have determined that deregulation and Retail Open Access would not be in the best interest of the citizens of Mississippi. There is no pending activity toward deregulation in the state at this time.

City of New Orleans

On September 17, 1997, ENO filed a rate case that included ENO's plan for a transition to competition. On November 6, 1997, the Council of the City of New Orleans ("Council") separated the rate case proceeding from ENO's competition plan and established separate gas and electric dockets to determine whether competition was in the public interest. At this time, the Council has taken no action with respect to retail open access for the electric customers.

Texas

The Texas legislature's Senate Bill 7 required all Texas utilities, including the Texas jurisdictional portion of EGS, to implement retail open access on January 1, 2002. However, in Dockets 24668 and 24669, the Public Utility Commission of Texas ("PUCT") determined that there were sufficient reasons not to implement retail open access in the portion of Texas that was not within the Electric Reliability Council of Texas ("ERCOT") as of January 1, 2002. In Docket 24669, which applied to EGS, the Commission found that the transmission business model that would allow full independence of the transmission system was not in place, and that retail open access would need to wait until such a system was in place. The PUCT's order in Docket 24669 provides a means to get to retail open access, and the earliest date that retail open access will be implemented within EGS' Texas jurisdiction is September 15, 2002. Activities are currently underway in Texas to meet this deadline. However, the progress of retail open access in Texas is closely tied to the progress of the SeTrans Regional Transmission Organization proceeding now pending at the Federal Energy Regulatory Commission.

Federal Activities

The Federal Energy Regulatory Commission ("FERC") has been, and continues to be, a strong proponent of increased competition in the wholesale power markets. The FERC has made open access to the transmission system the cornerstone of its efforts to increase wholesale market competition. The FERC's actions, as embodied in Orders 888, 889, and 2000, have had two significant results that bear on the development of the Entergy System's 2002 Resource Plan. First, as discussed in more detail later in this report, the amount of non-utility generation – including both Qualified Facilities ("QFs", or cogenerators) and independent power producers ("IPPs") – has grown substantially over the past few years, both nationally and within the Entergy region. Second, the FERC's orders have resulted in the functional separation of the transmission and generation components of the utility business, with full separation on the horizon. This means that resource (generation) planning has become much more complicated, because of the limitations on the information that can be shared between the separated generation and transmission functions.

Environmental Issues

Environmental issues affect the System's resource plan on several fronts. First, existing facilities must meet both existing and new environmental regulations for clean air and water. The cost of meeting these requirements, as well as Entergy's corporate goal of being one of the cleanest utilities in the country, must be factored into decisions concerning the ongoing operation of the System's existing generating fleet. Second, any acquisition of incremental generating resources must take into consideration the environmental impact with respect to environmental and economic goals.

Regulations

The 1990 Clean Air Act Amendments established minimum standards of air quality that states must meet. The Acid Rain Program seeks to reduce SO_2 and NO_x emissions, and specifically targets NOx emissions from coal-fired electric utility boilers. Both Texas and Louisiana have developed plans to comply with the Clean Air Act by reducing ozone levels in non-attainment zones. EGS's Texas service territory includes two non-attainment zones: Houston and Beaumont. EGS's Lewis Creek generating station is within the Houston non-attainment zone, and the Sabine station is within the Beaumont non-attainment zone. The Texas Natural Resource Conservation Commission ("TNRCC") has developed a plan for reducing ozone levels in these two regions that are intended to reach compliance with the Clean Air Act requirements by 2007. The Texas plan will cause EGS to incur additional costs for NOx controls through 2007. Entergy commenced projects in 2000 to engineer procure and construct needed air pollution control facilities. Cost estimates will be refined as engineering design progresses based on final strategies approved by the Environmental Protection Agency (EPA.). In November 2001 the Louisiana Department of Environmental Quality (LDEQ) issued a draft rule for control of NO_x to help bring the Baton Rouge area into ozone attainment by May 2005. The draft contains certain provisions that would lead to installation of new NO_x control equipment at certain EGS generating units. The final rule is expected to be in place by March 2002. The cost to bring these existing units into compliance with TNRCC and LDEQ rules is currently being studied.

Additional activity at the Federal level may include more stringent environmental legislation that includes new emissions limits to both existing and new generating units. This resource plan desires to maintain a clean and diverse resource portfolio that will be flexible enough to meet all environmental targets efficiently and effectively.

Transmission Issues

Transmission issues are adding an increasing layer of complexity to resource planning. Increasing transmission congestion is limiting the ability to move electrical power from the generating source to the load. Any consideration of the level and type of resources to meet forecasted load must include issues of transmission service availability and reliability.

FERC

FERC Order 888 issued in April 1996 provided for fair access to transmission resources for wholesale power and required that electric utilities no longer operate as vertically-integrated entities. Planning for generating resources now takes place independently of transmission planning.

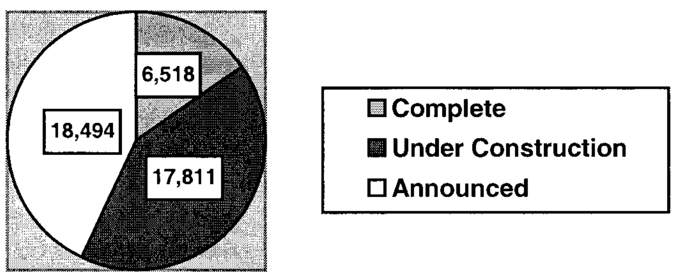
The viability of alternative market-based resources such as long-term purchase agreements is also affected by transmission congestion. In addition, there is the possibility that in the future Liquidated Damages energy may not be allowed as a designated network resource. The System has relied on this resource in the past.

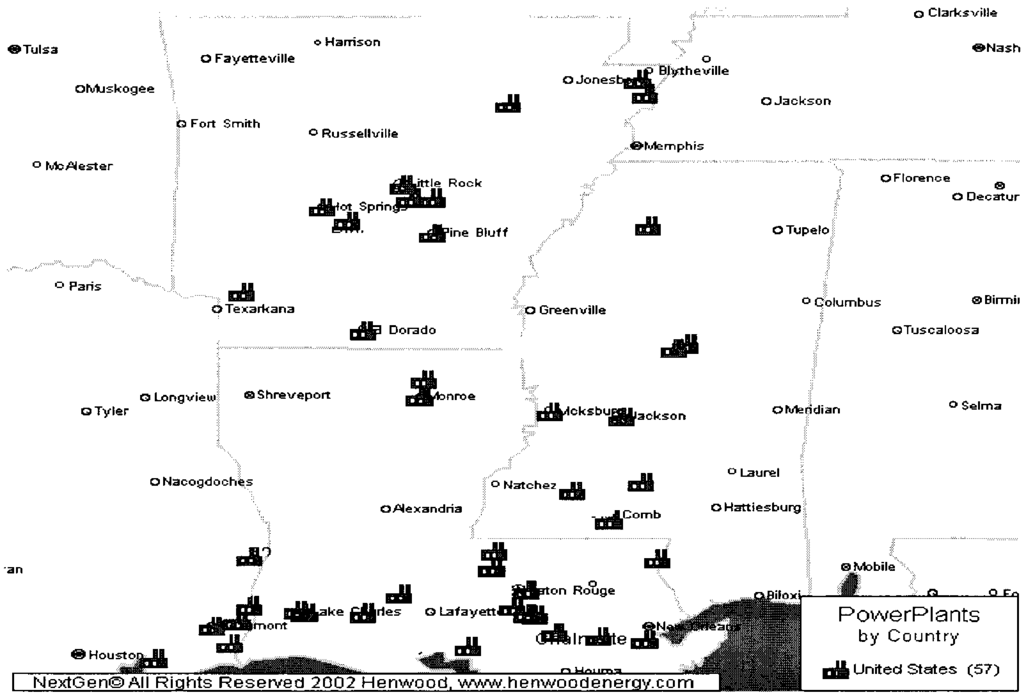
Generation Issues

Merchant Generation

There has been, and continues to be, significant activity by the merchant generation industry within the region. In fact, there are nearly 43,000 MW of new merchant generating capacity either operating, under construction, or planned within Louisiana, Arkansas, Mississippi, and the non-ERCOT portion of east Texas. The Henwood NextGen© map below shows 57 projects in the Entergy System control area alone. (Detailed information is provided in the Appendix.)

Merchant Generation





This 43,000 MW, either complete, under construction, or announced in the region is comprised of 70 different merchant projects. These projects are owned, operated, or developed by over 40 different owners or developers. Ten owners or developers control approximately 60 percent of the total capacity. A summary of activity by the ten largest developers is shown below:

Top Ten IPP Owner/Developers in the Entergy System Control Area

		Megawatts (MW)			
Owner\Developer	Projects	Complete	Under Construction	Announced	Total
Calpine	6	224	1,597	2,150	3,971
NRG Energy	8	1,412	1,520	292	3,224
Duke Energy	5	510	1,900	620	3,030
TECO Power	4	-	2,349	335	2,684
Tenaska	2	830	-	1,800	2,630
Cogentrix	3	-	2,436	-	2,436
Panda	2	-	1,110	1,300	2,410
Intergen	2	-	1,235	900	2,135
CLECO	3	775	943	-	1,718
LS Power	1	-	-	1,600	1,600

Those merchant generation facilities that have cogeneration capabilities and as a result have been certified as a Qualified Facility (QF) by the FERC are an issue of importance for the Entergy region. QFs are allowed to operate and place their electrical generation onto the System's grid in which case the System is obligated to purchase ("sink") this generation paying the owner/developer avoided cost for the electrical output, with no assurance that the generation will remain available as a supply resource for next hour or next day utility demand requirements. The QFs in the region would represent over 4,000 MW's of capacity and, without adequate avoided energy purchase power provisions, the forced purchase requirement in off-peak periods might cause the System to re-dispatch its own units in order to sink all of this added generation. The table below identifies the new QF units in the System control area, their size, and their status.

Qualified Facility ("QF") Generation in the Control Area

	Location	MW
Complete:		
Fina/BASF	Port Arthur, TX	80
Sabine River Works	Orange, TX	420
Exxon	Baton Rouge, LA	248
Pine Bluff Energy	Pine Bluff, AR	224
		972
Under Construction:		
AEP-Dow	Plaquemine, LA	900
Carville Energy	Carville, LA	440
RS Cogen	Lake Charles, LA	425
Occidental Chemical	Taft, LA	812
		2,577
Announced:		
Occidental Chemical	Convent, LA	588
Shell	Geismar, LA	80
		668
		4,217

Wholesale Power Market Expectations

Downward pressure on power prices is anticipated to continue, caused by expectations that generating supplies will continue to grow faster than demand in the region. As power prices decrease, as they have already, it is likely that not all of the merchant generation announced within the region will be completed as planned. However, there have been few cancellations for projects planned to come on-line in 2002-2003, and forward prices reflect the market's expectations that most of the near-term generation will be completed as planned. In the longer term, the recent decline in the financial position of many of the merchant development companies place more of the uncompleted capacity under uncertainty. At least four merchant companies developing projects in the region have seen their bond ratings recently downgraded by financial ratings agencies. Also, an ENRON subsidiary, NEPCO, an engineering, procurement, and construction company is involved in developing projects in the region.

In an effort to better assess the true status of the projects that have been announced within the region, Entergy's Generation Planning group has visited most of the plant sites currently under construction to assess the status of these projects. Through these site visits and actual on-site inspections, the Generation Planning group can confirm that the following amounts are reasonably expected to come on-line.

Merchant Capacity Under Construction Visited by Entergy Services Generation Planning			
	2002	**2003**	**2004+**
Arkansas			
Louisiana			
Mississippi			
Texas			
Total			

Fuel price risk

Entergy's electricity production costs are subject to fairly substantial swings as a result of price volatility in primary fuel markets. This was especially evident during the winter of 2000-2001 when natural gas prices rose to levels four times higher than the previous winter. Much of the price risk associated with the run-up in natural gas was mitigated by having a diverse portfolio of generating resources that uses nuclear, coal, gas and oil as primary energy sources. This diversity in generating resources allows the Entergy Operating Companies to shift production among generating units and fuel sources in order to minimize the impacts of price increases in a particular fuel. The ability to shift between natural gas and fuel oil in many of the System's generating units provides the ability to take advantage of price differentials between the two fuel supplies to minimize production costs.

In addition to maintaining generating fuel diversity, the System has attempted to mitigate natural gas price risk in its Louisiana-jurisdictional Operating Companies (EGS, ELI and ENOI) by entering into financial hedges designed to reduce the volatility of the System's cost of natural gas, pursuant to orders from of the LPSC and the New Orleans' City Council. These entities consumed approximately 60% of the total gas the System used for electric production in 2001. The gas hedge strategy incorporates a "layered purchase" approach that over time will trade off some of the opportunity to purchase fuel at the lower prices in return for avoiding some of the risk of purchasing the fuel at higher prices. The current financial hedges take the form of financially settled forward contracts for a portion of the forecasted natural gas requirements. The volume of gas included in the program for a given month is hedged by entering into several financial swaps over time, each for a portion of the month's volume. The System also minimizes its exposure to volatility in the natural gas markets by employing a strategy in which approximately one-half of its short-term gas requirements are met via purchases from the monthly (or "bid-week") market, with the remaining portion acquired through the next-day gas markets.

Furthermore, the System's coal-fired generation acts as a significant hedge to gas price volatility. By relying on coal-fired generation for part of its resource needs, the System potentially avoids some of the gas price volatility risks. The System's coal-buying strategy is consistent with the overall goal of reducing exposure to the risks associated with the cost of fuel. The System procures coal via a mix of long-, intermediate-, and short-term purchase contracts. The volumes to be included in each type of contract term will be purchased using several contracts, executed at predetermined times, and executed such that each contract expires at different points in time.

Key Near-Term Issues

Market Price

The Into-Entergy market prices for financially firm, liquidated damages energy and call options have dropped dramatically over recent months reflecting the expectation of an abundant supply of energy in the Entergy System region over the near term. This expectation extends out for the foreseeable future and the System expects prices to remain soft, based on the futures markets. The price and availability of these and other energy products make investment in long-term resources less economic than the short-term alternatives. The key questions center on how long these prices will remain below those of the long-term alternatives and at what point will the long-term alternatives become economically viable.

Transmission Market Structure and Transmission Service Availability

Considerable uncertainty remains as to the ultimate structure of the Transmission market. The FERC has effectively separated the generation and transmission planning functions with the intent of creating a totally independent and impartial transmission marketplace. However, this separation means that there is a forced lack of coordination between Entergy's generation and transmission functions, which may ultimately produce a suboptimal solution at the expense of the System's native load customer. The Entergy Operating Companies must stand in line with unregulated generation market participants for transmission service to meet the needs of their native load customers, which introduces a significant level of uncertainty into both long and short term resource planning. It is unclear, at this time, what the transmission market will look like in the future, and the issue of who will determine how the transmission system will be expanded, and who will pay for these expansions, remains a key question.

Chapter
3

The Development of the Entergy System Resource Plan

Long-Term Resource Requirements

There are three general aspects of the System's resource planning process: a forecast of the load that the System expects to need to be able to serve, a determination of the capability of the System's existing resources, and a determination of the amount of additional resources that will be needed to reliably meet the System's load.

Load Forecasting

Long–Term Reference Forecast

The System relies on three different methodologies to develop multiple independent views for a long-term "reference case" peak load requirements forecast. These three forecast methodologies are averaged and rounded to the nearest 50 MW to provide the baseline forecast used to develop this resource plan. The rationale for using three different methodologies is twofold. Foremost, the use of different methods allows the averaging out of extreme (too high or too low) results. Second, the resulting forecast could be viewed as essentially a type of consensus forecast. In addition to this "reference case" forecast, the evaluation of resource alternatives also considers scenarios for other possible load requirements reflecting major uncertainties such as extreme weather, the loss of large customers' demand as a result of co-generation or plant closure, and potential industry restructuring.

The three methods used to develop the long-term reference forecast were: 1) a point projection reflecting a temperature-adjusted trend escalation, (2) a long-term model reflecting the relationship of peak load and weather using statistically adjusted end-use models and 3) Entergy's traditional long-term load forecasting methodology using the Hourly Electric Load Model ("HELM"). Each method uses historical load data that were adjusted to reflect the load that might have occurred, had the System not curtailed customers under interruptible service contracts. In particular, the historical loads were adjusted upwards on those days and hours that experienced curtailments by the amount of requested curtailments.

The following table shows a comparison of load forecasts and actual peak loads experienced over the last three years, as well as the weather adjusted peaks over the same timeframe. The System peak load forecast for 2002 is about the forecasted peak for 2001 and is a result of customer losses and weak economic conditions. The table illustrates the degree of volatility inherent in the forecasting process. Over the three-year period the forecast and actual peak load varied by almost 2,000 MW or roughly 10 percent of the System peak load. The forecast volatility could be expected to be even greater over a longer-term planning horizon.

Load Forecast and Actual Peak Load Comparison

	1999		2000		2001		2002	
	MW	Temp.	MW	Temp.	MW	Temp.	MW	Temp.
Forecast	20,162	96 °	21,200	97 °	21,600	97 °		
Actual	20,664	97 °	22,052	103 °	20,257	93 °		
Weather Adjusted Actual	20,664	97 °	21,117	97 °	21,541	97 °		

Cogeneration Scenarios

The potential loss of customer load to cogeneration or self-generation adds another level of uncertainty to the forecasting process. The System relies on information obtained from its industrial customers through account representatives in the major accounts group for information about expected losses of load due to cogeneration. The October 31, 2001 cogeneration outlook from Entergy's major account group expected an additional MW of industrial losses by the summer of 2002. The cogeneration loss projection calls for MW of additional losses by the summer of 2003.

Regulatory Scenarios

The forecast comparisons above show changes of +1,000 MW to –500 MW from year to year. These dramatic changes from year to year are a result of changes in the underlying set of assumptions regarding economic conditions and specific customer activities. Long-term forecasts are subject to additional uncertainties associated with the changing regulatory environment. In order to address uncertainty about Retail Open Access (ROA) in Entergy's retail jurisdictions, nine separate scenarios were developed to reflect potential future retail load obligations. The "reference" forecast assumes a "business-as-usual" scenario where there is no customer loss resulting from implementation of ROA in any of the System retail jurisdictions. The table below shows the coincident peak loads for each of the System jurisdictions for the year 2002 through 2011. The nine different regulatory scenarios and forecasts are shown as well.

"Business-as-Usual" Coincident Peak Load Forecast

	COINCIDENT PEAK LOADS									
YEAR	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
SYSTEM										
HELM										
RECOMMENDED										
EAI										
ELI										
EMI										
ENOI										
EGS LA										
EGS TX										

Retail Open Access Scenario Peak Forecasts

	Peak Load Forecast (MW)									
Scenario	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Base Case										
w/o cogen losses										
w/o TX										
w/o TX, cogen losses.										
w/o TX, AR										
w/o TX, AR, cogen losses										
w/o TX, AR, LA										
w/o TX, AR, LA, cogen losses										
without TX, AR, LA Industrial										

Long-term Resource Requirements

Summary

- **The System resource requirement is assessed for the year 2011 as an indicator of long-term resource needs.**
- **The resource requirement is determined through probabilistic reliability assessment over a range of load forecasts.**
- **In conclusion, there is significant uncertainty in the level of the long-term incremental resource requirement.**

A key consideration in the decision to enter into incremental long-term resource commitment is the probability of being able to meet the forecasted needs with the existing generation resources. If the probability that future needs can be met with existing resources were sufficiently high, then a long-term commitment would not be justified, at least from a reliability perspective.

Currently, the methodology used to determine if there is an incremental resource requirement to reliably meet the forecasted system annual peak load is a Monte Carlo simulation model called ERAILS. This model compares, on a daily basis, available generation resources and the expected system firm load requirement. The available System generating resources include all available generating units with simulated forced outages, based on the historical performance of the units. The expected firm load requirement is based on the forecasted system load, plus or minus a 4% random variation and an instantaneous reserve requirement, less any non-firm system sales and curtailable load. The requirement is based on the additional MW that would be required to reduce the average number of times that a firm load customer would be interrupted to less than 1 day in 10 years Loss of Load Expectation (LOLE).

The ERAILS model has typically been used to assess the resource needs for the upcoming summer, when the system peak load generally occurs. However, it can be applied to longer term planning with a few basic modifications. Primarily, instead of using a single load forecast, nine different scenarios are used with probabilities assigned to each scenario. These scenarios are the ones designated as most likely to occur and are currently based on whether deregulation occurs in certain jurisdictions within the service territory. It is assumed that if deregulation occurs, there would be a loss of load as well as a loss of the generating assets owned by the associated Operating Companies in that jurisdiction. There are also scenarios that do and do not take into account the loss of additional load to cogeneration.

Currently, the probabilities of retail deregulation occurring by 2011 are estimated to be as follows:

Texas (non-ERCOT)	80%	Arkansas	30%
Louisiana	20%	Louisiana - Industrial Only	75%

In longer term planning, the magnitude of curtailable and limited firm wholesale load is less certain than it is in next-year planning. To adjust for the uncertainty of these loads, long term planning criteria is based on reserve deficit days instead of Loss of Load Expectation ("LOLE") days. Reserve deficit days is a measure of the number of days per year that the operating reserve (peak load minus available generation after reflecting probability of outages) falls to zero. This is the number of days per year that customers are potentially exposed to supply curtailments resulting from loads higher than available generating resources. Exposure to supply curtailments is a function of the amount of resources available. For the summer of 2002, the current planning criteria of 1 day in 10 years LOLE equates to a reserve deficit day criteria of approximately 0.75 days per month. By applying the same criterion to 2011, on average, the System would need to acquire up to an additional 4,500 MW for the summer peak of that year.

The plot below provides an indication of the distribution of reserve deficit results and also how the various scenarios contributed to the results. It shows the frequency and cumulative probability percentage of the maximum deficit that could occur in 2011 based on the nine scenarios and their assigned probabilities of occurrence. This plot indicates that there is approximately a 17% chance that there will be no deficit in the year 2011. On the other hand, if a deficit were to occur, there is an 80% chance that it would be MW or more. The bar lines in the plot show the range of results for each of the nine scenarios.

2011 Max Reserve Deficit Frequency

Out of 1000 Iterations

The result indicating a 17% probability of being able to meet the forecasted needs with the existing generation resources suggests there is a considerable risk that an investment in long–term resources may be unwarranted. As the probabilities assigned to the various scenarios are refined, this result may change. It is anticipated that this longer-term reliability analysis will continue to be performed annually to establish long-term resource requirements.

Chapter
4

Resource Acquisition and Utilization Strategy

Identification of Alternatives

Although the reliability assessment indicates that there may be no long-term need for incremental resources to serve Entergy's retail load, the question remains as to the most cost-effective way to reliably serve that load. In particular, there may be a question about whether or not Entergy's existing fleet could be cost-effectively replaced with more efficient new generation sources. In an attempt to broaden the field of potential long-term resource options, the System's planners considered a range of generation alternatives including retaining and/or increasing the capacity of existing System generating units, repowering of existing units, greenfield construction of new facilities and other alternatives related to owned generation. The planners also considered various types of firm wholesale products with counterparties (including power marketers, power brokers, and electric utilities) and firm wholesale power products traded in posted markets

The Entergy System is a major participant in the wholesale power market. System personnel who buy and sell in the wholesale power market surveyed the market participants with which the System regularly does business in order to determine what terms and conditions for various products might be available. The System's wholesale buyers also considered the products that were available on the over-the-counter market. Finally, to make sure that there were not any additional market opportunities that the System had overlooked, the System issued Requests for Proposals ("RFP") inviting wholesale market participants to offer capacity and/or energy products to Entergy.

Identify Long-Term Resource Alternatives

Existing Fossil Fleet

The advanced age of the System's fossil units suggests that at some point it may be more economical to replace existing fossil units with new capacity. Significant merchant generation has been developed and brought on-line within the region and even greater amounts of capacity are either under construction or in the planning stages. Downward pressure on power prices is expected to continue as the supply increases much quicker than the demand grows. As the System's fossil units age, the capital and O&M required for continued operation may increase. Therefore, the existing fleet was screened along with other long-term resources to assess whether it would be more economical to continue to maintain and operate the existing fossil units or to replace some portion of the fleet with new capacity.

Nuclear Uprate Projects

Uprate projects have been identified for each of Entergy's nuclear units; however, additional detailed engineering analysis is required to determine whether these uprate projects are feasible. In general, a nuclear uprate involves some change to the unit or its operations that results in a higher megawatt output from the unit. Either higher efficiency equipment may be installed that can produce more power from the same amount of fuel burned, or the unit may operate at higher pressures and flows to make the existing equipment achieve higher output. Before any nuclear uprate project is undertaken, engineering analysis must be performed to verify that the project is technically feasible and that safety is maintained. Because nuclear safety is the top priority, uprate projects must also be evaluated in light of other scheduled projects deemed necessary to ensure safety and compliance with Nuclear Regulatory Commission requirements. Additionally, an economic analysis must be conducted to assure that the project is economically justified.

For each nuclear unit in Entergy's fleet, both uprate projects based on modifications to equipment and modifications to operations have been identified. Uprates based on modifications to equipment are specific to each unit and, if feasible, could result in as much as an eight percent increase in output. Uprates based on modifications to operations are possible because the Nuclear Regulatory Commission modified its rules, effective July 31, 2000, to allow the use of updated feedwater flow measurement technology to achieve an uprate of something under 2%.

Greenfield Alternatives

In addition to the new Merchant Capacity under development in the region, the planners have screened various greenfield technologies identified in the current version of the Electric Power Research Institute ("EPRI") Technical Assessment Guide ("TAG") for generation supplies. Included in the screening process are 10 alternative Combustion Turbine designs, 7 alternative Combined Cycle designs, 6 Fluidized Bed Coal designs and 7 Pulverized Coal designs.

Combustion Turbines

A combustion turbine ("CT"), also called a gas turbine ("GT"), includes an air compressor, a combustor, and an expansion turbine. Gaseous or liquid fuels are burned under pressure producing hot gases that pass through the expansion turbine, driving the air compressor. The shaft of the CT is coupled to an electric generator such that mechanical energy produced by the CT drives the electric generator. Cost and efficiency criteria for the different CT designs that were screened in the process are shown in the table below.

	Unit Size (MW)	$/kW	Heat Rate (Btu/kWh)
Simple Cycle Combustion Turbine	50 - 230		
Aeroderivative Gas Turbine	27 - 45		
Steam-Injected Gas Turbine (STIG)	30 - 50		

Combined-Cycle Combustion Turbine

In a combined-cycle combustion turbine the hot exhaust gases from the CT pass through a heat recovery steam generator ("HRSG"), where they are cooled to between 200 $^{\circ}$ and 275° F, and in so doing, produce steam. The steam drives a steam turbine generator, which provides the bottoming cycle. Usually about two-thirds of the power is produced from the CTs, and one-third from the steam turbine generator.

	Unit Size (MW)	$/kW	Heat Rate (Btu/kWh)
Combined Cycle Combustion Turbine	77 - 512		

Coal Technologies

In addition to reviewing natural gas fired technologies, the various coal fired technologies currently available were reviewed:

	Unit Size (MW)	$/kW	Heat Rate (Btu/kWh)
Pulverized Coal			
Supercritical Pulverized Coal	300 - 400		
Subcritical Pulverized Coal	200 - 350		
Lime Spray Dryer	300		
Limestone Forced Oxidation	200 - 550		
Pressurized Fluidized-Bed Combustion Coal			
Conventional Systems	350		
Advanced Systems	677 - 688		
Atmospheric Fluidized-Bed Combustion Coal	200		

Merchant Plant Alternatives

On July 2, 2001 Entergy Services, Inc. (as agent for the Operating Companies) issued a Request for Proposals ("RFP") for power supply beginning May 1, 2004 for a ten-year term ending April 30, 2014. The RFP requested bids for capacity and energy from new and existing generating facilities.

In response to the RFP, 23 bidders submitted 40 proposals covering 17,350 MW of generating capacity. Of these proposals, 30 contained enough information to evaluate in the screening analysis.

A substantial number of the generating units submitted in response to the RFP are either under construction or in the planning stage. Of the alternatives that were bid in, 20 merchant generation sites are under construction within the System's four-state area, with a combined generating capacity of 15,135 megawatts.

As a result of the high number of generating units and megawatts not being operational at this time, the System is monitoring construction activity at the merchant generating facilities located within the control area.

Repowering of Existing Facilities

Over the years, the System has performed numerous assessments of potential incremental long-term resource alternatives. In both the 1992 and 1995 Least Cost Integrated Resource Plans prepared for the Entergy System, repowering of existing generating units proved to be among the least cost self-build options available to the System at that time. This is still the case in 2002.

To further refine the System's repowering options, the System has commissioned several studies over the years assessing the various repowering configurations available for the existing fossil fuel fleet. These studies include:

- A Raytheon report dated July 1998 on Conceptual Design and Rough Order of Magnitude Cost Estimates for Little Gypsy Unit 2 and Ninemile Point Unit 2.
- A Washington Group International (WGI) report from December 2000 on 7FA Repowering of 200 MW class units
- A Washington Group International (WGI) report from September 2001 on Definitive Engineering Phase Estimate Repowering of Michoud 2, Little Gypsy 1 and Willow Glen 2.
- Furthermore, the System has requested studies for transmission service for the period January 1, 2003 through January 1, 2025 for 17 existing plant sites identified as potential candidates for repowering, submitted in May 2001. System Impact studies were completed for all seventeen in December 2001.
- Interconnection requests submitted in June of 2001 for the following five sites: Michoud, Ninemile Point, Little Gypsy, Willow Glen and Nelson. Feasibility Study results was received in July of 2001.
- Facilities Studies requested for Michoud, Ninemile Point and Little Gypsy in August 2001. A Partial Facilities study was received in November 2001 indicating that about $1.8 million would be required to complete the connection.

Copies of these studies are provided in the Appendix.

Screening of Long-Term Resource Alternatives

Summary

As part of the evaluation of the various resource alternatives available to the System, a screening analysis template was developed to provide a relative ranking of alternatives, including greenfield development, long-term market purchases, maintaining existing fossil units and repowering projects. Given the disparate nature of these alternatives, the goal of the screening template was to utilize a consistent set of assumptions and calculations with which all alternatives could be evaluated and then comparatively analyzed. The end result of the screening analysis is a relative ranking of the long term resource alternatives based on the net present value total cost in $/MWh at capacity factors ranging from 1% to 80%.

Assumptions

In order to normalize the different options, a set of common assumptions was used to analyze each option. These assumptions included:

- An inflation rate, defined by the Consumer Price Index provided by WEFA;

- An assumed discount rate of 10.8% for all projects; and
- A consistent set of forecasts for gas and coal prices.

Also, several assumptions unique to each class of alternative were required. These included total unit capacity, capital cost, fixed and variable O&M costs, heat rates and start charges (if applicable). Assumptions unique to each alternative are described below.

Greenfield:
- All costing and operational characteristic information obtained from EPRI TAG Supply.

Long-Term RFP:
- Unless otherwise specified in RFP bid, O&M charges are escalated by the CPI;
- Unless otherwise specified in RFP bid, 100 starts or less per year were assumed.

Existing Units:
- Operating cost information reflect the forecasted capital and non-capital costs necessary to maintain existing units at their current operating levels.
- Heat rate assumptions were based on full load heat rates, similar to the other alternatives; and
- Unit capacities were based on 2000 average ratings

Repowering:
- Capital cost information obtained from Washington Group Definitive Engineering Phase Estimate.
- O&M cost estimates for a new combined cycle unit obtained from EPRI TAG Supply;
- Repowered heat rate assumption based on full load heat rate; similar to other alternatives

Methodology

Overview

The screening analysis calculates the levelized total cost in $/MWh of all resource alternatives over a range of capacity factors to compare and rank the greenfield, long-term purchase, existing fossil units and repowering projects. The total cost consists of 1) fixed cost – capital cost and fixed non-fuel O&M and 2) variable cost – fuel cost and variable non-fuel O&M.

Fixed Cost

For each alternative, the annual capital cost and annual fixed non-fuel O&M cost is summed to calculate the annual fixed cost. The source of these costs is as described below:

For greenfield units and repowering projects, the annual capital cost was determined by converting the construction cost into a levelized payment over the expected life of the project. For greenfield units the fixed non-fuel O&M is based on published estimates (source: EPRI TAG-Supply). For repowering, fixed non-fuel O&M is extrapolated from existing annual fossil unit budgets.

For long-term purchases, the annual capital charge equates to the annual capacity charge, and fixed non-fuel O&M is as quoted in RFP response.

For existing fossil units the annual capital cost is the annual capital budget and fixed non-fuel O&M is extrapolated from annual fossil budgets.

Variable Cost

Variable costs are composed of fuel and variable non-fuel O&M costs.

The annual fuel cost is calculated by multiplying the annual energy production by the heat rate and the fuel cost. Similarly, the annual variable non-fuel O&M is calculated by multiplying the annual energy production by the variable non-fuel O&M rate. For each alternative, at each capacity factor, the annual fuel cost and annual variable non-fuel O&M cost is summed to calculate the annual variable cost.

Total Cost

For each alternative, at each capacity factor, the annual fixed cost and annual variable cost are combined into the levelized total cost expressed in $/MWh.

Period

Each project is analyzed for a 10-year period over a range of capacity factors (from 1-80%). The 10-year period was selected to mirror the long-term RFP time frame.

Fuel Sensitivities

Analysis was performed with three fuel cost scenarios. These fuel cost scenarios were established as a base case, a low case and a high case. The high and low case represent +/- 25% change in the base case (approximately the estimated average range of fuel prices over the term of the analysis.) The curves located in the appendix represent the forecasted fuel prices for the term of the analysis.

Additional Sensitivity Analysis

In addition to the fuel sensitivity cases, other analyses were performed by varying several of the other input variables, including fixed O&M, installed capital cost, and unit life. The fixed O&M and installed capital cost were varied from the base case by +/- 25%. The unit life was varied from 10 – 30 years.

Comparison And Ranking

For each fuel case and at each capacity factor, all resource alternatives are sorted from lowest total cost to highest total cost. The most economic peaking resources are picked from the alternatives sorted at low capacity factors and at the opposite end of the range, the most economic base load resources are picked from the alternatives sorted at high capacity factors.

Results

The results indicate that continued maintenance and operation of the System's existing fossil units is more cost effective than replacement with new capacity. This conclusion remains consistent across the range of assumptions and sensitivies discussed above.

From a fixed cost perspective, the budgeted capital cost and O&M expense is lower for the existing fossil units than the estimated capital cost and O&M expense for new capacity or the equivalent market cost for capacity options. Even when the energy savings from the higher efficiency of new capacity is considered, the total cost of the new units is higher than the cost of the majority of the System's existing fossil fleet. Further analysis may be warranted if the capital costs or O&M expenses of the existing fossil units significantly increase above these sensitivities or if market-based resources become available at a cost lower than the new unit proxy cost.

Each of the identified nuclear uprate projects was reviewed using the screening analysis template and the results indicate that the nuclear uprate projects are among the lowest cost incremental resource alternatives. Engineering analysis will be performed to verify that the uprate projects are technically feasible and that safety is maintained. If proven technically feasible, safe, and economically justified these projects will be implemented.

Rankings of the various alternatives were made at different capacity factors. The complete list of rankings is contained in the Appendix.

All in Costs by Type

For further analysis, all alternatives were grouped collectively into their respective type and analyzed against other like grouped alternatives. Alternatives were pooled into the following types: New Build – CC; New Build – CT; New Build – Coal; Existing – Coal Units; Existing – Gas Units; Repowering Projects; RFP – 10 Year.

The grouped alternative types were then analyzed across a range of capacity factors in each of the fuel scenarios. The following curves represent the calculated costs associated with each type of alternative across this range of capacity factors in $/MWh, these curves are displayed below.

All-In Costs for Resource Alternatives Screening Results
Base Fuel Case Scenario

Capacity Factor

The graph above illustrates the costs of all of the screened resources over a range of potential capacity factors. When compared to new incremental generating sources, Entergy's existing units are the least cost alternatives at capacity factors of 47% and below. In other words, for a new resource to displace existing capacity, it would have to run at a 47% capacity factor or greater. The existing gas fleet currently operates at an average 36% annual capacity factor.

All-In Costs for Resource Alternatives Screening Results
High Fuel Case Scenario

Capacity Factor

The screening analysis was tested for sensitivity to high and low fuel prices. The graph above illustrates the costs of all of the screened resources assuming a **higher** fuel cost scenario. When compared to new incremental generating sources, Entergy's existing units are the least cost alternatives at capacity factors of 37% and below. In other words, for a new resource to displace existing capacity, it would have to run at a 37% capacity factor or greater. This level is roughly equal to the average capacity factor of Entergy's gas-fired fleet.

All-In Costs Resource Alternatives Screening Results
Low Fuel Case Scenario

Capacity Factor

The graph above illustrates the costs of all of the screened resources assuming a **lower** fuel cost scenario. In this scenario, Entergy's existing units are the least cost alternatives at all capacity factors of 65% and below. In other words, for a new resource to displace existing capacity, it would have to run at a 65% capacity factor or greater. This level is considerably higher than the capacity factor at which Entergy's gas-fired units operate.

Repowering vs. Short-Term Resource Cost Comparisons

Capacity Factor

The repowering option proved to be the least-cost long-term incremental resource to the System over a range of different assumptions. However, when compared to short-term resource options, it proved to be more expensive. The graph above compares the cost of repowering to the cost of alternative short-term resources based on the asking price provided in the summer RFP process. Over a range of capacity factors, the short-term purchases prove to be less expensive than the long-term repowering option.

Revenue Requirements Modeling

Based on the initial screening process three resource options were selected for more detailed analysis: 1) repower existing unit; 2) build new CC; and 3) build new CT. For each of these three alternatives a model was prepared projecting annual revenue requirements. In addition, the model projected levelized revenue requirements per unit of output ($/MWh) over time horizons of ten and thirty years. The latter was considered to be the depreciable life of the unit. Each alternative was analyzed under both high (60%) and low (15%) capacity utilization factors. Thus, the modeling produced four cases: 1) high capacity utilization – ten years; 2) low capacity utilization – ten years; 3) high capacity utilization – thirty year-life; and 4) low capacity utilization – thirty-year life. The analysis assumes that the repowering option is undertaken in time to provide capacity during the summer of 2004.

The revenue requirements analysis produced results that were consistent with the screening level analysis. Repower resulted in the lowest revenue requirements in all four cases. The ranking of the other options depended on capacity utilization. CC revenue requirements were lower than a CT in the high capacity utilization cases. CT revenue requirements were lower than a CC in low capacity utilization cases. These results are summarized in the following two tables.

Levelized Revenue Requirement ($/ MWh) @ 60% Capacity Factor

	10 Year	Life (30 Year)
Repower Existing Unit		
Combined Cycle Combustion Turbine		
Simple Cycle Combustion Turbine		

Levelized Revenue Requirement ($/ MWh) @ 15% Capacity Factor

	10 Year	Life (30 Year)
Repower Existing Unit		
Simple Cycle Combustion Turbine		
Combined Cycle Combustion Turbine		

Repowering results in the addition of MWs of new high efficiency capacity. However, repowering displaces MWs of existing capacity. The potential cost of replacing this capacity was considered by assuming that the equivalent of MWs would be purchased at fifteen percent capacity factor during peaking periods. The analysis indicated that at prices below $ /MWh the repowering option remains preferred over the CCGT. Given the current market expectations, prices in the summer of 2005 are not likely to exceed this level.

The implication of deferring the repowering option one additional year was then investigated. This analysis assumed that repowering would be undertaken in time to provide power during 2005 (as opposed to 2004) with equivalent power in 2004 provided through purchases. The final results of this analysis showed that delaying the repower decision an additional year does not increase revenue requirements as long as purchases in 2004 can be made at or below in all hours (assuming a 60% capacity factor for repowering). Given that the current bid/ask for the calendar 2004 is / , this analysis indicates that repowering would likely remain economic if deferred an additional year.

Conclusions

The long-term resource assessment reveals that the System's recent strategy of meeting its incremental resource needs with short-term wholesale energy purchases remains the most reasonable approach for meeting the resource needs of its customers. The System is continuing to evaluate the nuclear uprate projects that have been identified and if proven technically feasible, safe, and economically justified these projects will be implemented. At this time, other than the nuclear uprate projects, the cost of long-term resources is higher than the cost of meeting each year's resource need with short-term purchases. However, the System will take reasonable steps to maintain the options available to it for long-term resource acquisitions, and will continue to evaluate the overall economics of the short-term and long-term strategies. If and when it becomes more advantageous to the Operating Companies' customers to lock-in long-term resource alternatives, that is the strategy will be employed.

The preference for a resource strategy that relies on short-term purchases is supported by the following conclusions:

Short-term Market Trends:
While the forward price curve for power is uncertain, at this time short-term purchases are less expensive than long-term resources. The a substantial amount of merchant generation has come on-line within the Entergy region, and it appears likely that even more will enter the market within the near future. This suggests that short-term purchased power will be readily available, and that there will be continued downward pressure on power prices.

Incremental Resource Requirement Uncertainty:
In 2002, the Entergy System is short summer capacity; however, within the 10-year planning horizon, there are some possible future scenarios in which the System does not need additional resources.

Long-term Resources:
Repowering is the lowest cost long-term resource now available to the System. Once a unit is repowered, it has a life of 30 years. More significantly, the customers of the Operating Companies would be expected to bear the incremental capital costs of repowering a unit for at least ten years. Repowering, as an available long-term resource, is completely within Entergy's control. Therefore, the decision to repower a unit can be deferred at this time, but the option to do a repowering remains viable with minimal costs.

1995 Vs. 2002:
In 1995, RTS of ERS units was the lowest cost resource next to short-term purchases; similarly, in 2002, repowering is the lowest cost resource next to purchases. In both 1995 and 2002, the lowest cost resource next to purchases is solely within Entergy's control. Therefore, the major difference between 1995 and 2002 is that RTS required 6 – 8 months lead time; whereas, repowering requires at least 30 months lead time. The RTS decision could be reviewed on an annual basis and when more economic for the next 5 years, could be made available for the next summer and thereafter. The repowering decision can be reviewed on an annual basis and when more economic for 10 years, can be made available in 30 months.

Timing For Repowering:
Ideally, repowering should commence 30 months prior to the summer when the price of short-term purchases for the next 10 years exceeds the cost of repowering and Entergy is short capacity for those 10 years.

Risks:
Given the 30 month lead time for repowering, at most the Operating Companies' customers are exposed to short-term market prices for two summers. Given the life of a repowered generating unit, participation in the short-term market may be limited for several years.

Recommended Strategy:
These conclusions lead to the following strategy: First, annually assess summer short-term market price and depth. Second, continue to monitor IPP and QF development within Entergy's control area, which provides insight to future market prices and depth. Third, annually assess resource requirements for a 10 year planning horizon, and compare long-term resources to to short-term market alternatives to determine whether repowering or some other long-term resource options – either a long-

term purchase or a self-build options -- remains the most economic long-term resource. Finally, take the necessary steps to maintain repowering as a viable resource option.

Chapter

5

Short-Term Resource Acquisition and Utilization Strategy

Short-term Reference Forecast

In addition to the three different methodologies mentioned in Chapter #3, the System uses an artificial neural network short-term forecast developed by an outside vendor to provide a fourth perspective on near-term requirements. These four forecast methodologies are averaged and rounded to the nearest 50 MW to produce the baseline forecast used in the annual capacity planning process. The rationale for the use of four different methodologies is twofold. Foremost, the use of different methods allows the averaging out of extreme (too high or too low) results. Second, the resulting forecast could be viewed as essentially a type of consensus forecast. The following table summarizes the results of the four forecasts.

Short-term Reference Forecast

METHOD	PEAK FOR 2002 (MW)	PEAK FOR 2003 (MW)
Trend Projection		
RER–ECON		
RER- Trend		
HELM		
Average		
Recommended for Planning		

Cogeneration Scenarios

The System relies on information obtained from its industrial customers through account representatives in the major accounts group for information about expected losses of load due to cogeneration. The October 31, 2001 cogeneration outlook from Entergy's major account group expected an additional MW of industrial losses by the summer of 2002. The cogeneration loss projection calls for an additional loss of MW by the summer of 2003.

Short-term Resource Requirements

The annual resource planning process seeks to identify the amount of incremental resources necessary (above existing generation) to serve firm load at a reliability level of no more than one-day-in-ten-years loss of load expectation and to serve interruptible retail and limited-firm wholesale loads

with an average of ten or fewer days of interruption during the summer. As discussed in Chapter #3, the ERAILS model is used to evaluate the System reliability needs on an annual basis.
The ERAILS results table below considers incremental capacity in the range of MW for the summer 2002 period. A more detailed description of the ERAILS model is provided in the Appendix. A summary of the results of the 1,000 ERAILS Monte Carlo simulations is shown in the table below.

2002 ERAILS Model Results							
	Interruptible Load Interruptions					Firm Load Interruptions	
	Deficit Days			Deficit MW		Average	Average
Purchase	Min	Average	Max	Average	Max	Occurrence	Magnitude

The rows highlighted in ***bold italics*** in the results table indicate that between MW and MW of incremental resources are needed for the summer of 2002 to satisfy firm load and interruptible load reliability criteria. For example, the " " row indicates that, with the addition of MW, the average occurrence of firm load interruptions would be 0.11 days per year (or slightly more than one day in ten years), and the average magnitude of that firm load deficit would be MW. It also indicates that interruptible and firm wholesale loads would be interrupted 1.83 days on average, which meets the criteria of 10 days, and that the average magnitude of the interruption would be 1025 MW.

Resource Mix

Having identified the magnitude of the resource requirement, the next question is to determine the mix of resources to fill the requirement. The appropriate short-term resource mix is a function of the resource requirement quantity and duration, and the relative cost of the resources available to fulfill that requirement. In general, if there is an expectation of a resource need exceeding a certain number of days, this need should be met with energy products. If the need is expected for fewer days, it can be met with options to purchase energy at a specific "strike" price. The relationship between the must-take energy price, the option premium and its strike price determines the least cost mix of the energy and capacity products. In a static market, one can solve for the least cost mix. However, in a dynamic market, this approach is only valid for incremental purchases. Two approaches have been utilized to identify a target resource mix.

The first approach utilizes a **"deficit duration curve"** generated from the simulation results from ERAILS. That curve, which is shown below, indicates the number of days in which additional resources are needed to meet the System's reliability criteria. For example, the deficit duration curve indicates that, for the one day in ten-year scenario, a deficit situation would occur in approximately summer days in 2002 if no additional resources were acquired.

The deficit duration curve is used to help determine the quantity of each type of additional resource that would be appropriate based on the characteristics of each type of resource alternative and the needs of the System. The System can expect to take delivery of firm energy products every day specified in the contract, and can expect that unit-contingent energy products will be delivered almost every day (pursuant to the contract) as well. Thus, it is appropriate to obtain firm energy products (i.e., liquidated damages purchases or unit-contingent purchases) to meet that portion of the deficit duration curve where there is a need for a significant number of days. As shown in the figure, the System has determined that approximately MW of firm energy products – which may be needed for days during the summer of 2002 to meet the System's planning criteria – are necessary.

The deficit duration curve also indicates that the System plans to meet MW of expected resource needs through firm energy purchases from the short-term market (week-ahead, day-ahead, etc.) This approach is reasonable because it provides the System with the flexibility to respond to changing market conditions, unit availabilities, or System loads. In addition, by leaving MW of resource requirements uncommitted, the System leaves a portion of its requirement open for other purchase opportunities that may come available at potentially attractive prices.

Capacity products give the System the right to call on capacity when it is needed, but do not obligate the System to take energy when it is not needed. These products are most appropriate for meeting that portion of the deficit duration curve when the System is not sure it will need incremental energy, but requires some form of insurance that energy will be available if needed.

2002 Deficit Duration Curve
with Example Portfolio

Days

The figure above indicates that the System has determined that the resource plan for the summer of 2002 should include approximately MW of capacity products. In the one day in ten year case that underlies the deficit duration curve, all or part of that MW of capacity products would be expected to be called upon for reliability purposes as many as days. However, the System has not limited its capacity products to days; rather, this capacity can be used whenever it is needed for reliability or when it proves to be economical.

The final type of resources used to meet expected resource needs in the summer of 2002 are interruptible / curtailable loads. As shown above, interruptible / curtailable loads are expected to be used as the incremental resource for approximately 5 days, or less, during the summer period.

The second approach to the analysis of the resource mix evaluates the least-cost combination of firm energy and capacity products. This analysis, initially prepared in late November, 2001 (shortly after the ERAILS model results were considered to be reasonably final), first considered the cost of meeting all of the deficit identified in the ERAILS analysis with firm energy products. Then, the cost of meeting the deficit using a combination of firm energy products and call options was evaluated, substituting call options for firm energy products in 100 MW increments, until the least-cost combination of firm energy products and call options was identified. This analysis indicated that between MW and MW of capacity targets should be included in the resource mix for the summer of 2002. A copy of this analysis is provided in the appendix.

The two approaches account for the fact that the appropriate resource mix is a function not only of the deficit duration curve, but also of market prices, and therefore the resource mix may change with time. If, for example, the premiums associated with call options are out of line with prevailing market prices for firm energy products, it may be reasonable – at the actual time that contracts for resources are executed – to modify the mix so as to minimize the total cost to the System's ratepayers.

Short-Term Resource Alternatives

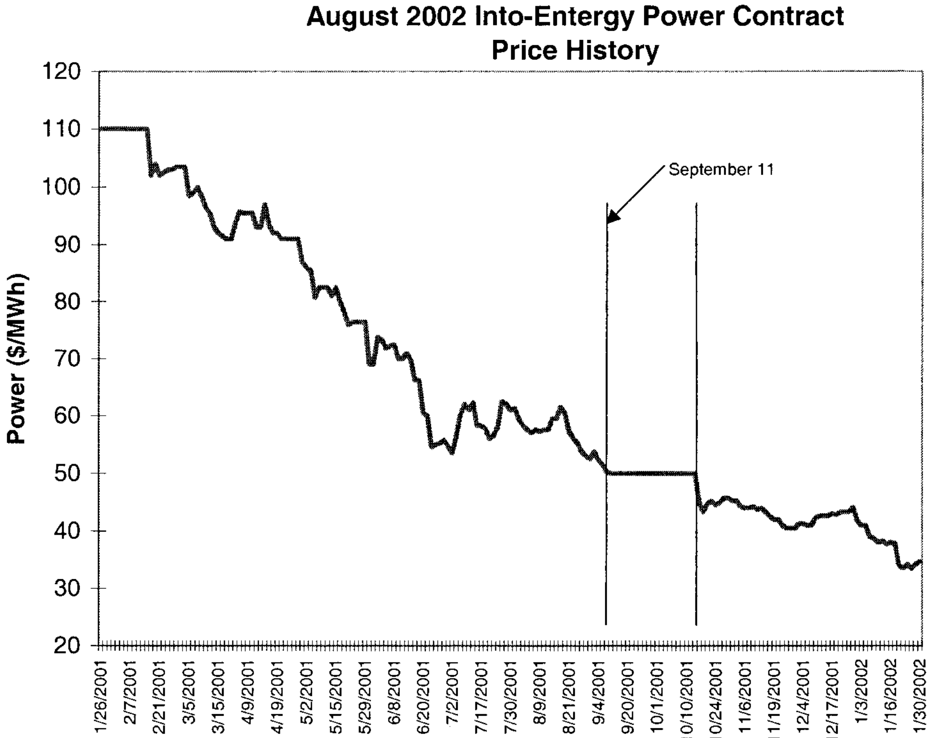
Both repowering and greenfield construction were eliminated as near-term (2002) options because they currently are (a) economically less attractive than other alternatives, (b) not available to be put into service in time for the summer of 2002, and (c) problematic given the uncertainties regarding the regulatory regime under which those plants would operate.

Wholesale Market Assessment

The "Into Entergy" wholesale futures market has become vibrant and actively traded over recent years. Two basic products are currently traded and available in this market:

- Liquidated Damages energy sold as standard blocks of 5x16 on-peak energy delivered over a monthly period into the Entergy Transmission System at any open interface designated by the seller.
- Liquidated Damages daily call options sold as the right, but not the obligation, to purchase a standard block of 1x16 on-peak energy at a predetermined price when notified by 9:00 AM the prior business day.

The System has purchased both products in the past to serve its energy needs during the summer months. The futures contracts for Summer 2002 have dropped precipitously over the time period for which they have traded. The 5x16 monthly product serves as the market benchmark for energy delivered into the Entergy system. The graph below shows the trading history of the August 2002 futures contract.



Summer 2002 RFP

On December 5, 2001 Entergy Services, Inc. issued a Request for Proposals ("RFP") for Power supply beginning June 1, 2002. The RFP requested bids for energy and/or capacity for periods ranging from 3 months to 3 years in length with a required availability period of June 1, 2002 through August 31, 2002.

In response to the RFP Entergy received bids for 4,325 MW of power supply covering the summer of 2002. These bids were from 16 bidders and were categorized into five different product types as listed below:

- Firm Energy products
- Capacity Products (Call Options)
  - Fixed Price call options
  - Heat Rate call options
  - Market Price call options
- Tolling Agreements

Firm energy products are contracts in which the bidder (supplier) is obligated to deliver and Entergy (receiver) is obligated to receive contracted energy all eligible hours, usually 5 days per week, 16 hours per day, during the contract period. Price and schedule of delivery are typically set in advance. Variants of this product might be contracts for delivery and receipt of energy around the clock, seven days per week, twenty-four hours per day.

Capacity products are contracts in which the purchaser (Entergy) has the right, but not the obligation, to purchase energy (call) at a price set forth in the contract. The supplier (bidder) is paid a fee called a "premium" as compensation for the obligation to supply the energy. This premium is generally expressed in terms of dollars per megawatt-hour ($/MWh) or dollars per kilowatt-month ($/kw-mo). The premium can be viewed as a capacity reservation fee paid for the right to call energy.

Capacity products submitted in the RFP process were three types. They were:

Fixed Price Call Options – the strike price for the purchase of energy is set forth in the contract, in terms of $/MWh ($50 per MWh) and is usually fixed for the term of the contract.

Heat Rate Call Options – the strike price for the purchase of energy is determined by a formula incorporating a fixed unit heat rate, in terms of Btu per kilowatt-hour, times the daily price of natural gas on the day the energy is called. The price may include other factors the supplier might deem applicable such as variable O&M, transportation, and fuel use taxes.

Market Price Call Options – the strike price for the purchase of energy is set at the daily "market" price on the day the energy is called. This type of option guarantees availability of supply but does not guarantee the price at which the supply can be purchased. This product is generally used for reliability purposes; however it also provides access to additional sources of market energy.

The last product category is Tolling Agreements. Tolling Agreements are contracts in which the purchaser (Entergy) has rights to "call" on certain generating capacity. In turn, the supplier is usually paid a fee, or capacity payment, for use of their generating capacity. The fee is generally stated in terms of $/kW for each month of the contract. When the purchaser "calls" on generating capacity they are expected to provide the supplier all fuel associated with start-up, operations, and shut-down of the generating capacity. Also, the supplier usually requires payments to cover variable O&M for the megawatts generated.

Entergy will seek to negotiate the terms and duration of its short-term agreements in order to meet its reliability criteria at the lowest reasonable cost.

Screening of Short-Term Resource Alternatives

Summary

As part of the evaluation of the various short-term resource alternatives, the same basic screening template used for long-term resources was applied to the Summer 2002 RFP bids. These bids ranged in contract duration from three months to over three years, with product types ranging from energy products to market priced call options with a capacity payment. The goal of the screening analysis was to yield a relative ranking of the short-term resource alternatives using a common set of assumptions and calculations developed in the long-term resource process. The results are ranked based on the net present value of total cost in $/MWh.

Methodology

The screening model requires several inputs and assumptions for each resource option. The inputs include capacity offered, capacity charge or call premium, contract term, fixed and variable O&M costs, heat rates, and start charges, if applicable. Combined with the analysis assumptions described below, each project is analyzed for the specified contract period over a range of capacity factors from 1% to 50%. Calculations were performed to develop the alternatives total cost in $/MWh which includes both capacity and energy dollars (fuel, O&M)

In order to normalize the different options, a set of common assumptions was used for each analysis. Assumptions included:

Inflation rate defined by the Consumer Price Index provided by WEFA
Discount rate assumed to be 10.8% for all projects
Unless otherwise specified in RFP bid, O&M charges do not escalate
Unless otherwise specified in RFP bid, assumed 100 starts or less per year.

Results

For analysis purposes, the bids for short-term resources were grouped into five general types: 7x24 energy products, 7x24 call options, 5x16 energy products, 5x16 call options, and $50 strike call options. Given the current flat power market, the bids did not vary significantly based on duration of the contract.

Results for each type of alternative are given in discounted total cost in $/MWh.

Results are based on a 30% capacity factor for call option products while energy products are for the specified hours (usually 47% of available hours in a given period.) Resulting product price ranges are given below for each product type offered.

Short-Term Resource Alternative Results

	Bid Ranges	
	Low ($/MWh)	High ($/MWh)
7x24 Energy Product		
7x24 Call Option		
5x16 Energy Product		
5x16 Call Option		
$50 Strike Call Option		

The System began acquiring resources for the summer of 2002 as early as the summer of 2001. Based on the concept of "layered purchasing", the System determined that acquiring resources over a longer period of time, as opposed to acquiring all of its identified resource needs over a period of a few months, would reduce the System's exposure to volatility in the wholesale power markets.

As of March 1, 2002, the System has entered into agreements to purchase MW of liquidated damages products for June, 2002 and MW of liquidated damages products for July and August, 2002. These agreements are summarized in the Appendix.

The System has also entered into an agreement for a MW on-peak unit-contingent purchase for June through August, 2002. This agreement provides up to MW of unit-contingent energy for all on-peak hours of the period, and up to MW for off-peak hours.

The System has not yet entered into any capacity agreements to date but is currently negotiating with a number of vendors for a variety of capacity products, including call options and other forms of capacity purchases.

Implications of the Short-Term Strategy

The System's strategy of short-term purchases, implementing nuclear uprates when feasible, maintaining the repowering option, and monitoring other long-term resource alternatives is appropriate considering the current and expected short-term market conditions. Uncertain long-term resource requirements in conjunction with the apparent overabundance of merchant capacity further supports avoiding long-term commitments in favor of flexible short-term alternatives. The System's short-term strategy is currently the lowest cost approach for satisfying resource requirements and by maintaining flexibility, the System is positioned to take advantage of emerging opportunities while responding to evolving market conditions.