EXECUTIVE SUMMARY

Kentucky Utilities and Louisville Gas & Electric (the Companies) continually evaluate their resource needs. The purpose of this study is to update this ongoing analysis and determine an optimal resource strategy for the Companies. The optimal strategy is determined based on a minimum expected Present Value of Revenue Requirements (PVRR) criterion and subject to certain constraints, including unit operating characteristics and maintaining a target reserve margin of 14%.

As precursors to the optimization process, two independent technology screening analyses were conducted, one for supply-side alternatives and the other for demand-side management (DSM) programs. The purpose of the supply-side screening analysis was to evaluate, compare and suggest the least-cost supply-side options to use in Strategist® optimizations. An independent screening analysis was conducted on numerous demand-side management options and ultimately recommended five new programs for consideration within Strategist®. The new DSM programs evaluated range from 0.4 kW to 17 MW. The DSM programs would only serve to delay the supply-side expansion strategy and not reorder it. Therefore, supply-side optimizations were run initially without the DSM programs. Once the least cost supply strategy was determined, the DSM options were included and a comparison was made to the case without the programs.

In order to consider uncertainty in the process, a rigorous evaluation of several key assumptions was conducted. These sensitivity cases quantified the effects on the optimal plan of various load and fuel forecasts, unit retirements, increases in coal unit capital cost and decreases in the combustion turbine (CT) and combined cycle (CC) units O&M expenses. Base case results conclude that the construction a second coal unit at Trimble County in 2010, followed by a Greenfield CT in 2013, WV Hydro Inc's Purchase Power Agreement (PPA) in 2014, two Greenfield CTs in 2015, one Greenfield CT in each year from 2016-2018, and a Greenfield supercritical high-sulfur coal unit in 2019.

With regard to the new DSM programs evaluated, inclusion of the programs produced a lower PVRR. Therefore, based on the current cost estimates and load impact associated with it, it is recommended that the five programs be implemented along with the expansion plan.

Introduction

The purpose of this study is to produce a multiple year Integrated Resource Plan for Kentucky Utilities Company and Louisville Gas & Electric Company (the Companies). The optimal plan is determined based on a minimum expected Present Value of Revenue Requirements (PVRR) criterion over a 30-year planning horizon and subject to certain constraints, including a target reserve margin of 14% and unit operating characteristics.

This report will first discuss the various modules of the Strategist® computer model used in the analysis. Next, the reserve margin used in this analysis will be briefly discussed followed by a discussion of the results of the supply-side screening analysis. A separate screening of Demand-Side Management (DSM) options has also been completed and will be discussed last. Based upon these supporting analyses, initial lists of technologies of various types and capacities will be suggested for further analysis within the optimization module of Strategist®. Sensitivities developed around five key areas (load, fuel, unit retirements, capital cost of the coal unit, and the O&M (operation and maintenance) cost of combustion turbine and combined cycle units) will be evaluated in computer optimizations and the least cost plan will be presented for consideration.

An Overview of the Strategist® Computer Model

The Load Forecast Adjustment (LFA), Generation and Fuel (GAF), Proview (PRV), and Capital Expenditure and Recovery (CER) modules of the Strategist® computer model were used in the study. The Strategist® computer software program can be used to either optimize a set of resource alternatives (determine a least-cost strategy under a prescribed set of constraints and assumptions) or evaluate a single pre-specified plan. Input parameters to the Strategist® model are described in Appendix A of this document.

The LFA module allows the user to create typical monthly load shapes for each company modeled to be transferred to the GAF module for production costing purposes. Inputs to the LFA are each modeled company's peak and energy load forecasts for multiple years and a historical load shape. Two companies are modeled in detail within the LFA. Kentucky Utilities and Louisville Gas and Electric Company (the Companies) are modeled together and make up one of the two companies while Owensboro Municipal Utilities (OMU) is the second company. OMU is modeled due to the unique purchase power agreement it has with the Companies. The demand and energy modeled for KU/LGE is after any peak and energy reductions associated with Interruptible or Curtailable customers. Existing DSM programs are then modeled separately within the LFA.

The GAF module simulates power system dispatch and operation using a load duration curve production costing technique. Production costs including fuel, incremental operation and maintenance (O&M), purchase power and emission costs are calculated in this module. Inputs to the GAF include generating unit and purchase power characteristics, fuel costs and unit or fuel specific emissions information.

PRV is an optimization module that evaluates all combinations of potential options to produce a list of resource plans, subject to user specified constraints, that satisfy the Companies' minimum target reserve margin criterion. PRV combines production cost analysis with an analysis of new construction expenditures (or DSM implementation costs) to suggest an optimal resource plan and sub-optimal resource plans based on minimizing utility cost. PRV receives revenue requirements information associated with capital expenditures from the CER. Inputs to PRV include generic generating unit characteristics from the GAF, DSM information from the LFA, and construction/implementation parameters such as each option's first year available.

The CER module calculates revenue requirements associated with capital expenditures for both the construction and in-service periods. PRV receives project-specific revenue requirement profiles for possible in-service dates from the CER for use in optimizations. The revenue requirement profiles are combined with the GAF production cost analysis to produce a total system revenue requirement for the study period. The CER contains capital information on resource projects associated with the optimal Integrated Resource Plan. Inputs to the CER include construction cost profiles, depreciation schedules and various economic assumptions.

Supporting Studies

Several supporting studies are utilized in this evaluation. These studies support the target minimum reserve margin, the supply-side technologies and the DSM program used in this evaluation.

Minimum Reserve Margin Target Criterion

In January of 2005, a study was completed to determine an optimal reserve margin criterion to be used by the Companies. This study recommended that a target reserve margin of 14% be used in long range planning studies. Accordingly, in the evaluation and development of this optimal

Integrated Resource Plan, the Companies have used a reserve margin target of 14%. The reserve margin study titled ***2005 Analysis of Reserve Margin Planning Criterion*** (January 2005) can be found in Volume III, Technical Appendix.

Supply-Side Technology Screening Analysis

As a precursor to the optimization process, a technology screening analysis was conducted. The purpose of the screening analysis was to evaluate, compare and suggest the least-cost supply-side options to use in Strategist® optimizations. The number of supply-side options available necessitates that a screening analysis be conducted since modeling of all options in Strategist® is simply not feasible. The supply-side screening report ***Analysis of Supply-Side Technology Alternatives*** (November 2004), can be found in Volume III, Technical Appendix. The supply-side technologies suggested by the screening evaluation for detailed analysis within the Strategist® model are shown in Table 1.

Table 1
Supply-Side Technologies Suggested for Analysis with Strategist®

Supercritical Pulverized Coal unit at Trimble County Station (TC2)
WV Hydro Power Purchase Agreement (PPA)
Supercritical Pulverized Coal, High Sulfur – 750 MW
Run of River-Ohio Falls Expansion (Units 9 and 10)
Combustion Turbines at a Greenfield Site
Combined Cycle Combustion Turbine (Un-Phased)

The options listed in Table 1 are the options that passed the screening analysis and represent the complete list of supply-side alternatives available to Strategist®. Since the 2002 IRP, the Companies made two CCN filings with the Commission: Trimble County Units 7 through 10 (Case

No. 2002-00381); Trimble County 2 (Case No. 2004-00507). At this time, the Companies continue to pursue possible opportunities through the RFP process and through participation in the wholesale marketplace on a real time basis. Currently, in the CCN process, purchase opportunities are compared to construction alternatives to arrive at an optimal strategy. Peaking type purchase power opportunities in optimizations would serve only to evaluate the delay of CT construction for short periods of time, which is already being considered by the Companies in greater detail (in the CCN process). Regardless of the method or the arena in which the evaluation is conducted, the Companies will continue to evaluate the benefits of purchase power, both short- and long-term, through participation in the wholesale marketplace on a real time basis as a method to delay generation construction.

Demand-Side Technology Screening Analysis

In addition to the supply-side screening discussed above, a demand-side screening was performed. More than 70 demand-side options underwent a qualitative screening evaluation, the results of which suggested that twenty-seven demand-side programs be evaluated further in a quantitative evaluation. The results of that evaluation indicate that five new demand-side programs be considered for implementation. Collectively, the new DSM programs are expected to reduce the Companies' system peak by approximately 30 MW by the summer of 2011. The existing DSM programs are assumed to continue into the near future and have not been included in the optimization process. These programs are "hardcoded" in the Companies' load data similar to the way an existing generating unit is modeled in the unit data. Because the sizes of the DSM programs are small when compared to competing supply-size options, it is intuitive that the program will not completely eliminate a new unit from the expansion plan. Instead, the program could serve to defer new construction in the event that a small amount of capacity is needed to maintain the target reserve margin. Therefore, the DSM programs will be evaluated only after the optimal expansion plan is developed. If the case that includes the DSM programs lowers the expected PVRR of the expansion plan, then the programs will be included in the Companies' plans to meet future needs. More details regarding all the Demand Side Management programs, including the cost of the new programs can be found in the report tiled ***Screening of Demand-Side Management (DSM) Options*** (December 2004) in Volume III of the Technical Appendix.

Base Case Development

Using the supply-side options identified in Table 1 along with the base assumptions for the demand and energy forecast, fuel forecast and new unit capital costs, an initial expansion plan can be developed. Appendix A of this report details all of the existing units' operating characteristics as well as documents all of the load forecasts (base, high and low), fuel prices (base, high and low) and SO_2/NO_X emission cost information used in this evaluation. Table 2 below details relevant information pertaining to each of the supply-side options evaluated. There is a reserve margin shortfall in 2009 of approximately 40 MW. The reserve margin was allowed to drop for that year to approximately 13.4%. It is most likely that a deficit in 2009, if any, will be met with a power purchase.

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Table 2
Supply-Side Alternatives Data

All Costs are in 2004 $

	Net Capability		Overnight Installed	Total Non-Fuel Variable O&M	Total	Full Load HHV		Required	First	FGD Removal	NOx Emiss
	Summer[5]	Winter	Cost	Non-Ozone Season[6]	Fixed O&M[7]	Heat Rate	EFOR	Maint wks	Year	Efficiency	Rate
	(MW)	(MW)	($/kW)	($/MWh)	($000/yr)	(Mbtu/MWh)	(%)	per year	Available	(%)	(#/Mbtu)
Trimble County Coal[1]	549	563	[redacted]	0.90	7,300	8.865	7.00%	3	2010	98%	0.0500
WV Hydro PPA	181	99	[redacted]	[redacted]	N/A	N/A	0.00%	0	2010	N/A	N/A
Greenfield Coal	732	750	[redacted]	1.88	14,343	9.383	5.00%	3	2012	95%	0.1000
Ohio Falls Unit[3]	5	4	[redacted]	0.00	165	N/A	0.00%	0	2010	N/A	N/A
Greenfield CT[4]	148	181	[redacted]	13.13	4,930	11.132	5.60%	2	2007	N/A	0.0389
Combined Cycle	484	563	[redacted]	3.93	11,581	7,032	5.26%	2	2007	N/A	0.0389

Notes to Table 2:
1 All appropriate data for the coal unit at Trimble County assumes that KU/LGE would own 75% of the new unit.
2 The WV Hydro PPA has only an energy expense. The PPA energy cost is given in 2008 dollars.
3 The existing Ohio Falls layout has room for only two expansion units. The data represents a single generating unit.
4 "Greenfield" implies a location without a currently existing unit and infrastructure (fuel handling equipment etc).
5 Summer Ratings are used for the months of April - September.
6 Only the Pulverized coal options have a Non-Fuel Variable O&M cost that is different in the Ozone season due to the operation of NOx control equipment.
7 The Fixed O&M for Greenfield CTs and the Combined Cycle option include the cost associated with reserving gas-line capacity.

Several comments regarding the information contained in Table 2 are worth noting:

- Cost/Performance data for the CTs and Combined Cycle units are based on data provided by Black and Veatch (B&V) in September of 2004.
- Cost/Performance data for the Trimble County Coal option is based on data supplied by Burns & McDonnell and Cummins & Barnard and include the cost of both a Flue Gas Desulfurization system and a Selective Catalytic Reduction system.
- Cost/Performance data for the Ohio Falls options is based on an escalation of the cost evaluation supplied to the Companies by Voith/Siemens Hydro on May 31, 2002 and a budgetary estimate dated July 11, 2002. This budgetary estimate was not a detailed site-

specific estimate and does not take into consideration environmental issues that may exist at the Ohio Falls station regarding the installation of Ohio Falls 9 and 10.

- The first year available for each of the options is based on Company experience with construction of like projects and takes into account the expected regulatory processes for environmental permitting, construction time, etc.
- The Combined Cycle alternative represents an un-phased plant, meaning that both the combustion turbines and steam cycle are constructed prior to plant commissioning. This is in contrast to a combined cycle constructed in phases. B&V has estimated that phased construction of combined cycle power plants could potentially cost 10% more than un-phased construction due to such reasons as workforce remobilization once construction on each progressive phase is terminated and starts back and cost associated with stack relocation. Therefore the un-phased option will be the only option that is considered here.
- As mentioned earlier and reiterated here, no purchase power alternatives are evaluated in this analysis but will be evaluated within the required CCN application process.

For a more complete description of the origins of the data associated with each of the supply-side options see the ***Analysis of Supply-Side Technology Alternatives*** (November 2004) in Volume III, Technical Appendix.

With the summary of the supply-side cost and performance data, the least cost base plan identified by Strategist® can be evaluated. For future reference, this plan will be referred to as Plan "A" and it represents the 30-year expansion strategy that minimizes the Present Value of Revenue Requirements criterion given the assumptions for each alternative's cost and performance (shown in the preceding Table 2) and the assumptions of base load and base fuel forecast. The expansion plan for the fifteen year period (2005-2019) covered by the Integrated Resource Plan for Plan "A" and the PVRR associated with it are shown below in Table 3.

To facilitate the comparison of multiple plans, the names of the alternatives have been shortened. We have already discussed TC2, but WVHy represents the WV Hydro PPA alternative, GFCU is the 750 MW Greenfield Supercritical Coal Unit, the 148G represents the 148 MW Greenfield CT option, while the Combined Cycle unit and the Ohio Falls options will be referred to as CC#2 and Falls, respectively.

Table 3
Base Case Optimal Expansion Plan

Load Forecast:	Base
Fuel Forecast:	Base
Plan:	**"A"**
2004	
2005	
2006	
2007	
2008	
2009	
2010	1-TC2
2011	
2012	
2013	1-148G
2014	1-WVHy
2015	2-148G
2016	1-148G
2017	1-148G
2018	1-148G
2019	1-GFCU
30 Yr PVRR ($000)	17,634,704

As can be observed in Table 3, optimization results using the base assumptions indicate that the installation of a second coal unit at Trimble County be completed, followed by a Greenfield simple-cycle combustion turbine in 2013 and the WV Hydro PPA alternative in 2014. Four

Greenfield CTs complete the supply-side needs thru 2018, and a Greenfield supercritical coal unit is selected in 2019. The thirty-year PVRR for this case, in 2004 year dollars, is estimated to be $17.635 Billion.

Sensitivity Analyses

The supply-side alternatives identified in Table 2 were also evaluated in several other sensitivity cases. Sensitivities were performed in five areas: (1) load forecast, (2) fuel forecast, (3) unit retirements (4) coal unit capital costs and (5) the assumed O&M expense of the CTs and Combined Cycle units as a result of firm gas transportation requirements.

Sensitivity: Load

The load forecast is a significant factor influencing the Companies' Integrated Resource Plan. Each supply-side technology is designed for optimal unit performance at various levels of utilization. CTs, for instance, while relatively inexpensive to construct (compared to coal-fired units), are more costly to operate and maintain given the relative prices of gas and coal. Conversely, coal-fired units while expensive to construct, are relatively inexpensive to operate and maintain. The economics of adding a supply-side option to any generation system is based on the expected costs of operating (including any associated costs for environmental emission) and maintaining the unit over the full range of loads it is expected to serve. Significant economic penalties (costs higher than expected) may be incurred if the unit is operated above or below the level it was planned to serve. For example, if a CT was added to a system in which load was greater than forecasted, the utilization of the CT may exceed the economical range for which it was planned. In other words, it may have been more economical to install intermediate load serving capacity (such as Combined Cycles) or baseload capacity (coal or hydro) instead. Thus, load growth scenarios that are different from that which is currently forecasted may have a significant impact on the selection of an optimal technology type. Therefore, in order to evaluate the effect of various load forecasts, a load sensitivity analysis was incorporated into the process of determining an optimal resource plan.

In summary, the load sensitivity analysis consists of evaluating the effect of three load forecasts on the selection of resource alternatives. The three forecasts depict an expected system load growth case, a case where system load growth exceeds expected growth and a case in which system load growth is less than expected. For reference, the resulting forecasts are termed the base, high and low load forecasts. The details of and the basis for the various load forecasts are described in Volume II, Technical Appendices I-IV. A tabulated summary of these respective forecasts can be found in Appendix A of this document.

Table 4, below, shows the optimal expansion plans when optimization runs are made on the low (Plan "B") and high load (Plan "C") forecasts. For comparison purposes the optimization of the base load forecast (Plan "A") is also shown. The plans shown in Table 4 utilize the base fuel forecast and the cost/operation data. The inclusion of the 30-year PVRR for the sensitivities are for informational purposes (i.e. the high load forecast is expected to have a higher cost than either the base or low load forecasts) and is shown to indicate how much costs are affected by the sensitivities conducted.

Table 4
Load Sensitivity

Load Forecast:	**Base**	**Low**	**High**
Fuel Forecast:	Base	Base	Base
Plan:	**"A"**	**"B"**	**"C"**
2004			
2005			
2006			
2007			
2008			
2009			2-148G
2010	1-TC2		1-TC2
2011		1-WVHy	
2012			
2013	1-148G	1-TC2	1-148G & 1-WVHy
2014	1-WVHy		1-148G
2015	2-148G		1-GFCU
2016	1-148G		
2017	1-148G		
2018	1-148G	1-148G	1-148G
2019	1-GFCU	1-148G	1-GFCU
30 Yr PVRR ($000)	17,634,704	15,672,281	19,586,552
Cost Delta	1,962,423	-	3,914,271
Plan Rank (Low to High)	2	1	3

As with the base optimization, sensitivity optimizations around the forecasted load for the Companies continue to show that TC2 and the WV Hydro PPA are chosen prior to 2015. As should be anticipated, the occurrence of low load over the period as represented in Plan "B" results in the least cost PVRR, with Plan "A" (base load) and Plan "C" (high load) following respectively. It is noted that TC2's first year available is 2010. Allowing for an earlier install would result in the selection of TC2 in 2009 for the high load scenario, and the two 2009 CTs in Plan "C" would be delayed to 2011 and 2012.

Sensitivity: Fuel

A second significant factor (load forecast being the first) influencing the Companies' optimal Integrated Resource Plan is the fuel forecast. The Combustion Turbine and the Combined Cycle technologies, for example, are gas-fired while the Trimble County unit is a coal-fired technology. Thus, the relative prices of gas and coal may have a significant impact on the selection of an optimal technology type. Therefore, in order to evaluate the effect of gas and coal prices, a fuel sensitivity analysis was incorporated into the Companies' process of determining an optimal Integrated Resource Plan. The fuel forecasts were developed by increasing (decreasing) the expected cost of coal. The gas prices were not adjusted. Not adjusting the gas price is a relatively simple method for evaluating the impact of the "gap," or difference in cost between that of coal and gas.

In summary, three fuel price forecasts have been developed and were used in optimizations. For reference these forecasts will be called base, low and high fuel forecasts and can be found in Appendix A of this document. Obviously no fuel/energy price sensitivity was considered for the WV Hydro PPA or Ohio Falls options as those are run-of-river units. Table 5, below, shows the optimal expansion plans when optimization runs are made on the low (Plan "D") and high coal (Plan "E") fuel price forecasts. As before, Plan "A," the optimization for the base load, base coal forecast is shown for comparison purposes. The plans shown in Table 5 continue to utilize the base load forecast and the cost/operation data as was used in development of Table 4. The inclusion of the 30-year PVRR for each sensitivity is for informational purposes, as the high fuel forecast will have a higher cost than either the base or low fuel forecasts plans and is shown to indicate how much costs are affected by the sensitivities conducted.

Table 5
Fuel Sensitivity

Load Forecast:	Base	Base	Base
Fuel Forecast:	**Base**	**Low**	**High**
Plan:	**"A"**	**"D"**	**"E"**
2004			
2005			
2006			
2007			
2008			
2009			
2010	1-TC2	1-TC2	1-TC2
2011			
2012			
2013	1-148G	1-148G	1-148G
2014	1-WVHy	1-WVHy	1-WVHy
2015	2-148G	2-148G	1-148G & 1-Falls
2016	1-148G	1-148G	1-148G & 1-Falls
2017	1-148G	1-148G	1-GFCU
2018	1-148G	1-148G	
2019	1-GFCU	1-GFCU	
30 Yr PVRR ($000)	17,634,704	16,814,120	18,444,192
Cost Delta	820,584	-	1,630,072
Plan Rank (Low to High)	2	1	3

The fuel sensitivity, as in the load sensitivity, continues to show that TC2 should be constructed for a 2010 in-service, followed by a Greenfield simple cycle machine in 2013, and the WV Hydro PPA alternative in 2014 results in the least-cost expansion plan. The low fuel forecast decreases the 30-year PVRR (as compared to Plan "A") and the high fuel forecast increases the 30-year PVRR (as compared to Plan "A").

Sensitivity: Unit Retirement

Green River Units 1 and 2 were retired at the end of 2003 after determining it would be uneconomical to continue their operation. While no additional retirements are currently planned, the Companies have a number of units that are at least thirty-five years old [see the portion on *Aging*

Generating Units in Section 8.(5)(b)]. Furthermore, the relatively high production costs of these units and the upcoming 2010 Clean Air Interstate Rule ("CAIR") restrictions (as well as any future imposed environmental regulations) will only worsen their relative economics. It could become economic to retire many of these units even without a significant mechanical failure such as the one experienced at Pineville (see Table 1 in Appendix A of this report for units affected by this sensitivity). Because of this risk, a third sensitivity was conducted that retired approximately 180 MW of the Companies' summer capacity in 2010 (the first year of CAIR).

To simplify the retirement sensitivity, all units were assumed to retire simultaneously. The retirement scenario retired the units on December 31, 2009 (Plan "F"). The sensitivity utilizes the base load and the base fuel forecast. Table 6, below, summarizes the resulting optimal generation expansion plan and costs associated with the plan. As before, Plan "A" is shown for comparison.

Table 6
Retirement Sensitivity

Load Forecast:	Base	Base
Fuel Forecast:	Base	Base
Retire Units:	**No**	**Y 2010**
Plan:	**"A"**	**"F"**
2004		
2005		
2006		
2007		
2008		
2009		
2010	1-TC2	1-TC2
2011		
2012		1-148G
2013	1-148G	1-WVHy
2014	1-WVHy	1-148G
2015	2-148G	2-148G
2016	1-148G	1-148G
2017	1-148G	1-148G & 1-Falls
2018	1-148G	1-148G
2019	1-GFCU	1-GFCU
30 Yr PVRR ($000)	17,634,704	17,766,508
Cost Delta	-	131,804
Plan Rank (Low to High)	1	2

The results of the retirement sensitivity reveal optimal generation expansion strategies very similar to what the load and fuel sensitivities suggested: TC2 in 2010, followed by a Greenfield CT in 2012 and the WV Hydro PPA in 2013. The 2012 CT and WV Hydro PPA alternative are required one year earlier than the base case as a result of the retirement sensitivity.

Sensitivity: Coal Unit Capital Costs

Each of the optimizations conducted thus far has assumed that the Capital and Operation costs are as shown in Table 2 "Supply Side Alternative Data." A capital cost sensitivity and O&M cost sensitivity would greatly enhance the quality of the analysis and could possibly indicate that the identified alternatives become marginal or possibly even un-economical under these conditions. Conducting these fourth and fifth sensitivities will identify if and by how much the customers would benefit from the selection of an alternative technology to meet load growth and maintain reserve margin should capital costs or operation expenses differ from what is currently expected.

Because the capital cost of the coal unit is larger relative to other options, it will be the technology on which the Capital Cost sensitivity is based. The current capital cost estimate for Trimble County 2 is $1314 per kW and is based on detailed cost estimates provided by Cummins & Barnard. A sensitivity using a 5% increase in capital costs for all coal options was included. Plan "G" in Table 7 is the optimal expansion plan using the higher cost for the base load coal unit, base load forecast, base fuel forecast, and no unit retirements. As before, Plan "A" is shown for reference.

Table 7
Capital Cost Sensitivity

Load Forecast:	Base	Base
Fuel Forecast:	Base	Base
Other:	**TC2 1314 $/kW**	**TC2 1379 $/kW**
Plan:	**"A"**	**"G"**
2004		
2005		
2006		
2007		
2008		
2009		
2010	1-TC2	1-TC2
2011		
2012		
2013	1-148G	1-148G
2014	1-WVHy	1-WVHy
2015	2-148G	2-148G
2016	1-148G	1-148G
2017	1-148G	1-148G
2018	1-148G	1-148G
2019	1-GFCU	1-GFCU
	===========	===========
30 Yr PVRR ($000)	17,634,704	17,739,956
Cost Delta	-	105,252
Plan Rank (Low to High)	1	2
New Unit Capital PVRR	2,499,145	105,250
New Unit Fuel/O&M PVRR	1,940,270	-
Existing Unit Operating PVRR	11,889,377	-
Purch Pwr / Other Costs PVRR	1,305,913	-
	===========	===========
Total (match Delta above)	-	105,250

Table 7 indicates that should the installed capital cost of the coal-fired unit be approximately 5% more than is currently expected, it would still remain in the optimal generation expansion plan for a 2010 in-service. Examination of the breakdown of costs between the two cases indicates that an increase in the capital cost of the coal-fired alternative by 5% increases the PVRR by $105 Million and, as expected since the plans are the same, no other cost is affected.

Kentucky Utilities Company
and
Louisville Gas & Electric Company

2005 Optimal Expansion Plan Analysis

Prepared by

Generation Systems Planning

January 2005

2005 OPTIMAL INTEGRATED RESOURCE PLAN ANALYSIS

TABLE OF CONTENTS

Sensitivity: O&M Costs Associated with Combustion Turbines and Combined Cycle Units

The fifth sensitivity to be conducted is in regard to the Fixed O&M expenses associated with the simple-cycle CTs and combined cycle machines. The Fixed O&M costs shown in Table 2 for the Greenfield CTs, Trimble County CTs and the Combined Cycle include firm gas transportation. In the past, the availability of pipeline capacity in the summer meant that firm gas transportation was not needed in order to operate natural gas-fired units. Recently, pipeline capacity has become much tighter, requiring procurement of firm transportation in order to ensure that the Companies' gas-fired units can be dispatched when needed. Because of the uncertainty surrounding future gas pipeline capacity, a sensitivity was conducted that removed all gas transportation charges from the Fixed O&M of the simple-cycle CTs and combined cycle units. Exclusion of this expense may increase the number of Combined Cycles in the plan or cause the Combined Cycle alternative to become more economical than the other resource alternatives. Table 8 shows the resulting plan (Plan "H") if the cost was removed along side Plan "A" for comparison.

Table 8

CT O&M Cost Sensitivity: Optimal Expansion Plan With Coal Option Available in 2008

Load Forecast:	Base	Base
Fuel Forecast:	Base	Base
Other:	**Base**	**No Gas Res Charge**
Plan:	**"A"**	**"H"**
2004		
2005		
2006		
2007		
2008		
2009		
2010	1-TC2	1-TC2
2011		
2012		
2013	1-148G	1-148G
2014	1-WVHy	1-WVHy
2015	2-148G	2-148G
2016	1-148G	1-148G
2017	1-148G	1-148G
2018	1-148G	1-148G
2019	1-GFCU	1-GFCU
	===========	===========
30 Yr PVRR ($000)	17,634,704	17,455,984
Cost Delta	178,720	-
Plan Rank (Low to High)	2	1

The optimal expansion plan resulting from removal of firm gas transportation expense associated with the simple-cycle CTs (both Trimble and Greenfield) and the combined cycle is not significant enough to produce a different expansion plan prior to 2019. While it does lower the cost by approximately $180 Million, the optimal plan thru 2018 continues to be construction of TC2 in 2010, followed by a Greenfield CT in 2013, the WV Hydro PPA in 2014, CTs from 2015 to 2018, and a Greenfield supercritical coal unit in 2019.

Summary and Recommendations

The results of the optimization performed with the base load forecast, base fuel forecast, and base capital and O&M costs (shown in Table 2) that the plan previously identified as Plan "A" is the least-cost expansion plan for meeting the Companies' load requirements. The plan calls for a second coal unit to be constructed at Trimble County, followed by a Greenfield CT in 2013, the WV Hydro PPA in 2014, two Greenfield CTs in 2015, one Greenfield CT in each year from 2016 to 2018, and a Greenfield supercritical coal unit in 2019. This plan is supported by five sensitivities to key assumptions including the load forecast, fuel forecast, unit retirements, increase in the capital cost of the coal units and decreases in the operation and maintenance costs associated with the combustion turbines and combined cycle units. In six of the seven sensitivities, the optimal plan called for the construction of TC2 in 2010, followed by a Greenfield CT, and then the WV Hydro PPA. The only sensitivity that did not have the previous ordering is the low load forecast, which recommended the WV Hydro PPA in 2011 followed by TC2 in 2013.

Since the reserve margin deficiency is rather small in 2009, the capacity need could possibly be avoided with short term purchase power since a commitment to construction does not need to be made at this time. If a 14% reserve margin was maintained via construction in 2009, the 2013 Greenfield CT would be accelerated to 2009 with the remainder of the plan being unchanged. Therefore, prior to evaluating the new DSM program, this study would recommend that the optimal generation expansion strategy of the Companies be that shown in Plan "A".

Incorporation of DSM Program: Residential New Construction

If the plan is fixed such that the units are installed in the same years as Plan "A" and the five DSM programs are added (creating Plan "I") the change in PVRR can be observed and a determination made on whether the new DSM programs should be recommended (in that it lowers the 30-year PVRR) or tabled for further evaluation in the future. Table 9 shows how the PVRR of Plan "A" is affected after adding the five DSM programs (Plan "I"). While the installation dates of the new units are the same in both Plans "A" and "I," the notation was changed to highlight the fact that different PVRR occur due to the addition of the five DSM programs.

Table 9
KU/LGE 2005 Generation Expansion Plan
(with DSM Programs)

Load Forecast:	Base
Fuel Forecast:	Base
Other:	Plan "A" + DSM

Plan:	**"I"**
2004	
2005	
2006	
2007	
2008	
2009	
2010	1-TC2
2011	
2012	
2013	1-148G
2014	1-WVHy
2015	2-148G
2016	1-148G
2017	1-148G
2018	1-148G
2019	1-GFCU
30 Yr PVRR ($000)	17,611,278

Conclusion

By comparing the PVRR of Plan "A" with that of Plan "I", it can be seen that the five new DSM programs have lowered the 30-year PVRR by over $23 Million and therefore, based on the foregoing analysis it is recommended that the Companies implement both the supply-side plan identified as Plan "A" as well as the DSM programs. It is further recommended that purchase power continue to be reviewed as an option to delay generation construction.

2005 Expansion Plan

APPENDIX A

DATA ITEMS USED IN 2005 OPTIMAL INTEGRATED RESOURCE PLAN ANALYSIS

Existing System Data

The Strategist® computer program is used to simulate Kentucky Utilities Company's (KU) and Louisville Gas & Electric's (LG&E) generating systems. The model simulates the dispatch of both companies generating units and other purchases to serve load, and of Owensboro Municipal Utilities' (OMU) generating units and purchases to serve OMU's load while simultaneously maintaining the KU/LGE reserve margin requirements. The remaining generation available from OMU's units after meeting their requirements is economically dispatched by the Companies. The following sections outline the information and the sources of the information used to model the KU, LG&E and OMU generating systems.

A) General Data Items

1. Base Year – 2004

2. Study Period - 2004 to 2033 (with infinite end effects)

3. Economic Assumptions:

   Revenue requirements are determined on an annual basis and discounted to the base year giving a present worth of revenue requirements. Discounting is performed using a discount rate, which is assumed to remain constant for all years.

4. Financial Parameters:

a. Discount Rate:	7.14%
b. Capital/O&M costs Escalation Rates:	2.0%/2.0%
c. Combined Federal and State tax rate:	40.36%

5. Unit Retirements:

   Base Assumption:

   This evaluation reflects the recent retirements of Green River 1 and 2. The operating life of all other existing units is extended beyond the end of the study period.

   Sensitivity:

   A sensitivity was evaluated that considered the simultaneous retirement of aging units. The scenario assumed simultaneous retirement of the eleven units listed in Appendix A Table 1 on December 31, 2009.

6. Unserved Energy Cost

The cost placed on unserved energy is $400 per MWh (2004 dollars) escalated at 2% annually.

7. Load Forecast

KU/LGE Base: See 2005 Expansion Plan Appendix A Table 2a.
LG&E and KU March 1, 2004 Energy and Demand Forecast for 2004-2033 developed by Market Analysis.

KU/LGE High: See 2005 Expansion Plan Appendix A Table 2b.
LG&E and KU July 30, 2004 Energy and Demand Forecast for 2004-2033 developed by Market Analysis.

KU/LGE Low: See 2005 Expansion Plan Appendix A Table 2c.
LG&E and KU July 30, 2004 Energy and Demand Forecast for 2004-2033 developed by Market Analysis.

OMU Base: Developed May 5, 2004 by KU/LGE personnel based on historical data and information provided by OMU. See 2005 Expansion Plan Appendix A Table 2a.

8. Hourly Load Files

Market Analysis provides the KU and LG&E typical hourly loads files with all load forecasts used. OMU typical hourly loads files are developed based on an OMU historical load shape.

9. KU/LG&E Unit Data

a. Installed Capacity - See 2005 Expansion Plan Appendix A Table 3

b. Equivalent Forced Outage Rate - See 2005 Expansion Plan Appendix A Table 3

Average GADS data using historical data over a number of years that includes a major planned outage on each unit (or maintenance cycle). EFORs have been increased by inclusion of maintenance outage hours (MOHs) to better reflect actual unit availability.

c. Heat Rates - See 2005 Expansion Plan Appendix A Table 3

d. Fuel Cost –

Base Fuel Price Forecast Developed June 29, 2004

Base Fuel Price Forecast: See 2002 Expansion Plan Appendix A Table 4
High Coal Price Forecast: See 2002 Expansion Plan Appendix A Table 5
Low Coal Price Forecast: See 2002 Expansion Plan Appendix A Table 6

e. Maintenance Schedule

Maintenance inputs were determined by reviewing the Companies' projected maintenance as of late spring 2004. Planned outages are scheduled to optimize reserves and reliability over all months of each year.

10. OMU Unit Data

a. Installed Net Capacity

OMU (Smith Unit 1): 145/147 (summer/winter)
OMU (Smith Unit 2): 270/278 (summer/winter)

b. Equivalent Forced Outage Rate

OMU (Smith Unit 1): 13.6%
OMU (Smith Unit 2): 14.5%

Based on OMU historical GADS data

c. Heat Rates (Full Load)-

OMU (Smith Unit 1): 10,626 Btu/kWh
OMU (Smith Unit 2): 10,092 Btu/kWh

d. Heat Content of Fuel: 10,700 Btu/lb

e. Maintenance Schedules -

Planned outage inputs were developed with the assistance of OMU.

f. Contracted MW Demand Sale to KU - See 2005 Expansion Plan Appendix A Table 7.

g. Fuel Cost - See 2005 Expansion Plan Appendix A Table 8.

Fuel costs include associated costs for fuel handling and limestone.

h. OMU Scrubber O&M (Smith Units 1 & 2)
i. Variable O&M: Limestone charges included in fuel cost.
Removal Efficiency: 92%.

11. Other Purchases

a. Contract Demand - See 2005 Expansion Plan Appendix A Table 7

EEInc. (Firm): 200 MW each year

OVEC (Firm): 2004 through March 2006 is 209 MW, April 2006 and beyond is 179 MW

5x16 On-Peak Market Purchase; Weekday On-Peak Hrs-All Months (Non-Firm): 200MW

b. Forced Outage Rates

EEInc: 9.74% partial FOR (for example, EEI will supply less than 200 MW 9.74% of the time); Note: KU owns 20% of six units at Joppa. A single purchase unit was used to model KU's portion of the six units. Each unit was assumed to have the same FOR and the probability of KU's 20% being available was assigned to the purchase unit.

OVEC: NA

5x16 On-Peak Market Purchase: 5.0%

c. Full Load Heat Rate (Btu/kWh)

EEInc: 10,000
OVEC: 10,000
5x16 On-Peak Market Purchase: 10,000

For these transactions, which were modeled as purchase power units, the fuel price was input such that the fuel price times the heat rate would result in the expected energy cost of the purchase. A heat rate of 10,000 Btu/kWh is not meant to reflect the "real life" heat rate of the units associated with these transactions.

d. Heat Content of Fuel (Btu/lb)

EEInc: 10,800
OVEC: N/A
5x16 On-Peak Market Purchase: N/A

e. Fuel/Energy Cost

See 2005 Expansion Plan Appendix A Table 8

f. Maintenance

EEInc: A 33 MW derate for 13 weeks in the spring and fall (derived from EEInc. Joppa Historical Data).

OVEC: Maintenance requirements were provided by OVEC for calendar year 2003. The same profile is assumed for all other years.

Table 1- 2005 Expansion Plan Appendix A
Units Considered in the Retirement Sensitivity

Unit Type	Plant Name	Unit	Summer Capability (Net MW)	Current Age (Years)
Steam	Tyrone	1	27	58
Steam	Tyrone	2	31	57
CT	Waterside	7	11	41
CT	Waterside	8	11	41
CT	Cane Run	11	14	37
CT	Paddy's Run	11	12	37
CT	Paddy's Run	12	23	37
CT	Zorn	1	14	36
CT	Haefling	1,2,3	36	35

Table 2a - 2005 Expansion Plan Appendix A
Base Forecast: Peak (MW) /Annual Energy (GWh)

Year	LGE Forecast Peak (MW)	LGE Forecast Energy (GWh)	KU Forecast Peak (MW)	KU Forecast Energy (GWh)	OMU Forecast Peak (MW)	OMU Forecast Energy (GWh)
2004	2,579	12,417	3,967	21,273	184	909
2005	2,629	12,657	4,067	21,812	185	914
2006	2,673	12,870	4,153	22,273	186	923
2007	2,705	13,024	4,275	22,930	186	933
2008	2,756	13,266	4,387	23,530	187	941
2009	2,800	13,478	4,472	23,983	188	946
2010	2,850	13,722	4,549	24,399	189	950
2011	2,910	14,011	4,646	24,920	190	955
2012	2,964	14,269	4,731	25,376	191	959
2013	3,029	14,584	4,830	25,909	192	963
2014	3,088	14,865	4,925	26,420	192	967
2015	3,147	15,151	5,012	26,883	193	972
2016	3,203	15,421	5,089	27,298	194	976
2017	3,264	15,713	5,184	27,810	195	981
2018	3,333	16,047	5,290	28,377	196	985
2019	3,401	16,374	5,393	28,933	197	989

Peaks and energy forecast reflect effects of interruptible/CSR but not DSM.

Table 2b - 2005 Expansion Plan Appendix A
High Forecast: Peak (MW) /Annual Energy (GWh)

	LGE Forecast		KU Forecast	
Year	Peak (MW)	Energy (GWh)	Peak (MW)	Energy (GWh)
2004	2,588	12,460	3,972	21,299
2005	2,655	12,779	4,093	21,950
2006	2,715	13,069	4,198	22,516
2007	2,757	13,275	4,347	23,313
2008	2,825	13,600	4,481	24,040
2009	2,885	13,890	4,586	24,594
2010	2,953	14,219	4,681	25,107
2011	3,033	14,604	4,798	25,740
2012	3,106	14,955	4,901	26,290
2013	3,193	15,372	5,022	26,937
2014	3,273	15,759	5,137	27,560
2015	3,353	16,144	5,244	28,124
2016	3,430	16,510	5,338	28,635
2017	3,512	16,907	5,454	29,256
2018	3,604	17,349	5,582	29,945
2019	3,694	17,783	5,708	30,620

Peaks and energy forecast reflect effects of interruptible/CSR but not DSM.

Table 2c - 2005 Expansion Plan Appendix A
Low Forecast: Peak (MW) /Annual Energy (GWh)

	LGE Forecast		KU Forecast	
Year	Peak (MW)	Energy (GWh)	Peak (MW)	Energy (GWh)
2004	2,571	12,379	3,941	21,135
2005	2,606	12,545	4,017	21,541
2006	2,636	12,692	4,081	21,887
2007	2,659	12,799	4,173	22,381
2008	2,694	12,967	4,258	22,837
2009	2,723	13,108	4,321	23,176
2010	2,759	13,281	4,379	23,484
2011	2,799	13,476	4,451	23,877
2012	2,836	13,652	4,515	24,221
2013	2,880	13,865	4,590	24,624
2014	2,921	14,062	4,662	25,008
2015	2,962	14,260	4,727	25,354
2016	3,001	14,446	4,784	25,664
2017	3,043	14,647	4,856	26,050
2018	3,089	14,873	4,936	26,478
2019	3,135	15,093	5,014	26,898

Peaks and energy forecast reflect effects of interruptible/CSR but not DSM.

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Table 3 - 2005 Expansion Plan Appendix A

Louisville Gas and Electric/ Kentucky Utilities Generator Data

Unit	Installed Year	Summer Rating (MW)	EFOR %	Avg Heat Rate at Max Load (Mbtu/MWh)
Brown 1	1957	101	[redacted]	[redacted]
Brown 2	1963	167	[redacted]	[redacted]
Brown 3	1971	429	[redacted]	[redacted]
Brown 5	2001	117	[redacted]	[redacted]
Brown 6	1999	154	[redacted]	[redacted]
Brown 7	1999	154	[redacted]	[redacted]
Brown 8	1995	106	[redacted]	[redacted]
Brown 9	1994	106	[redacted]	[redacted]
Brown 10	1995	106	[redacted]	[redacted]
Brown 11	1996	106	[redacted]	[redacted]
Ghent 1	1974	475	[redacted]	[redacted]
Ghent 2	1977	484	[redacted]	[redacted]
Ghent 3	1981	493	[redacted]	[redacted]
Ghent 4	1984	493	[redacted]	[redacted]
Green River 3	1954	68	[redacted]	[redacted]
Green River 4	1959	95	[redacted]	[redacted]
Tyrone 1	1947	27	[redacted]	[redacted]
Tyrone 2	1948	31	[redacted]	[redacted]
Tyrone 3	1953	71	[redacted]	[redacted]
Dix 1-3	1925	24	[redacted]	[redacted]
Haefling 1-3	1970	36	[redacted]	[redacted]
Cane Run 4	1962	155	[redacted]	[redacted]
Cane Run 5	1966	168	[redacted]	[redacted]
Cane Run 6	1969	240	[redacted]	[redacted]
Mill Creek 1	1972	303	[redacted]	[redacted]
Mill Creek 2	1974	301	[redacted]	[redacted]
Mill Creek 3	1978	391	[redacted]	[redacted]
Mill Creek 4	1982	477	[redacted]	[redacted]
Trimble 1 (75%)	1990	383	[redacted]	[redacted]
Trimble 5	2002	160	[redacted]	[redacted]
Trimble 6	2002	160	[redacted]	[redacted]
Trimble 7	2004	160	[redacted]	[redacted]
Trimble 8	2004	160	[redacted]	[redacted]
Trimble 9	2004	160	[redacted]	[redacted]
Trimble 10	2004	160	[redacted]	[redacted]
Cane Run 11	1968	14	[redacted]	[redacted]
Paddys Run 11	1968	12	[redacted]	[redacted]
Paddys Run 12	1968	23	[redacted]	[redacted]
Paddys Run 13	2001	158	[redacted]	[redacted]
Waterside 7	1964	11	[redacted]	[redacted]
Waterside 8	1964	11	[redacted]	[redacted]
Zorn 1	1969	14	[redacted]	[redacted]
Ohio Falls	1928	48	[redacted]	[redacted]

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Table 4 - 2005 Expansion Plan Appendix A

Louisville Gas and Electric/ Kentucky Utilities Base Fuel Costs ($/Mbtu)

	Brown	Gr River	Tyrone	Ghent		Cane Run	Mill Creek	Trimble	Oil	Gas *	Haefling
	Units 1-3	Units 3-4	Unit 3			Units 4-6	Units 1-4				Units 1-3
Year	2.75# SO2	4.56# SO2	1.8# SO2	6.2# SO2	1.25# SO2	6.0# SO2	6.0 # SO2	6.0 # SO2			Gas*
2004	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2005	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2006	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2007	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2008	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2009	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2010	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2011	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2012	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2013	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2014	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2015	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2016	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2017	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2018	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2019	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

* Indicates a seaonal profile applies. Price shown is July price.

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Table 5 - 2005 Expansion Plan Appendix A

Louisville Gas and Electric/ Kentucky Utilities High Fuel Costs ($/Mbtu)

Year	Brown Units 1-3 2.75# SO2	Gr River Units 3-4 4.56# SO2	Tyrone Unit 3 1.8# SO2	Ghent 6.2# SO2	Ghent 1.25# SO2	Cane Run Units 4-6 6.0# SO2	Mill Creek Units 1-4 6.0 # SO2	Trimble 6.0 # SO2	Oil	Gas *	Haefling Units 1-3 Gas*
2004	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2005	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2006	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2007	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2008	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2009	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2010	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2011	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2012	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2013	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2014	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2015	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2016	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2017	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2018	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2019	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

* Indicates a seasonal profile applies. Price shown is July price.

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Table 6 - 2005 Expansion Plan Appendix A

Louisville Gas and Electric/ Kentucky Utilities Low Fuel Costs ($/Mbtu)

Year	Brown Units 1-3 2.75# SO2	Gr River Units 3-4 4.56# SO2	Tyrone Unit 3 1.8# SO2	Ghent 6.2# SO2	Ghent 1.25# SO2	Cane Run Units 4-6 6.0# SO2	Mill Creek Units 1-4 6.0 # SO2	Trimble 6.0 # SO2	Oil	Gas *	Haefling Units 1-3 Gas*
2004	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2005	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2006	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2007	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2008	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2009	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2010	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2011	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2012	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2013	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2014	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2015	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2016	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2017	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2018	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2019	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

* Indicates a seaonal profile applies. Price shown is July price.

Table 7 - 2005 Expansion Plan Appendix A

Kentucky Utilities/Louisville Gas and Electric
Purchases During Peak Month (MW)

Year	EEI (Firm)	OMU (Firm)	OVEC (Firm)
2004	200	184	179
2005	200	196	179
2006	200	195	149
2007	200	193	149
2008	200	193	149
2009	200	192	149
2010	200	191	149
2011	200	190	149
2012	200	189	149
2013	200	188	149
2014	200	187	149
2015	200	186	149
2016	200	185	149
2017	200	184	149
2018	200	183	149
2019	200	182	149

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Table 8 - 2005 Expansion Plan Appendix A

Modeled Energy Costs Associated with Purchase Alternatives ($/Mbtu)

Year	EEI (Firm)	OMU (Firm)	OVEC (Firm)
2004	[redacted]	[redacted]	[redacted]
2005	[redacted]	[redacted]	[redacted]
2006	[redacted]	[redacted]	[redacted]
2007	[redacted]	[redacted]	[redacted]
2008	[redacted]	[redacted]	[redacted]
2009	[redacted]	[redacted]	[redacted]
2010	[redacted]	[redacted]	[redacted]
2011	[redacted]	[redacted]	[redacted]
2012	[redacted]	[redacted]	[redacted]
2013	[redacted]	[redacted]	[redacted]
2014	[redacted]	[redacted]	[redacted]
2015	[redacted]	[redacted]	[redacted]
2016	[redacted]	[redacted]	[redacted]
2017	[redacted]	[redacted]	[redacted]
2018	[redacted]	[redacted]	[redacted]
2019	[redacted]	[redacted]	[redacted]