Source: Water & Light Tad

Agenda Item No: REP 170-13

To: City Council
From: City Manager and Staff MM

Council Meeting Date: Dec 16, 2013

Re: Electric System Integrated Resource Plan - 2013 Update

EXECUTIVE SUMMARY:

In August of 2013 Burns & McDonnell finished and delivered their "Final Report on the Columbia Water & Lights Integrated Resource Plan - 2013 Update". The next step was to develop the Staff Recommendations and Implementation Plan based on this 2013 IRP update. Included with this report is the 2013 Integrated Resource Plan Update for Columbia Water & Light's Electric System and the Staff Recommendations and Implementation Plan for the 2013 Integrated Resource Plan Update.

DISCUSSION:

An Integrated Resource Plan for an Electric System is comprised of an assessment of future needs and a plan to provide resources to meet those future needs. It is "integrated" because it looks at both demand side (conservation, energy efficiency, etc.) resources as well as the more traditional supply side (generation/ power plants, transmission lines, etc.) resources in making its recommendations on how best to meet future electric energy needs.

In August of 2013 Burns & McDonnell finished and delivered their "Final Report on the Columbia Water & Lights Integrated Resource Plan - 2013 Update". This plan is an update to the 2008 IRP by Burns and McDonnell. This 2013 Integrated Resource Plan (IRP) update outlines a plan for securing resources to meet Columbia Water & Lights (CWL) energy needs in a way that will minimize the cost to customers over time and maximize consumer benefits consistent with Columbia's environmental goals and standards. This update represents a comprehensive guiding plan for CWL's electric energy future.

The next step in this process was to develop the Staff Recommendations and Implementation Plan based on this 2013 IRP update. The purpose of this Staff Recommendations and Implementation Plan is to use the information developed in the 2013 IRP Update, other department studies, assessments and documents to develop this Columbia Water & Light Staff Recommendations and Implementation Plan. This document is intended to discuss recommendations and propose implementation plans. Included in the Staff Recommendations and Implementation Plan is a proposed Budget Year Cost Phasing chart showing project items proposed for Fiscal Year 2014 appropriation. In a series of meetings, staff worked with the Water & Light Advisory Board to develop this document and was recommended for City Council approval at their December 4th meeting.

Included with this report is the 2013 Integrated Resource Plan Update for CWL Electric System and the resulting Staff Recommendations and Implementation Plan.

FISCAL IMPACT:

None, Informational

VISION IMPACT:
http://www.gocolumbiamo.com/Council/Meetings/visionimpact.php

9.3 Goal: Columbia will work toward achieving maximum energy efficiency and transition to renewable energy sources.

9.3.1 Strategy: Invest in energy efficiency and renewable energy to protect Columbia's economy from energy dollar outflow.

9.3.2 Strategy: Educate the public in areas of energy conservation, renewable energy resources, climate change, and economic implications of energy uses.

9.3.3 Strategy: Enact regulations and adopt policies to implement better, more efficient technologies.

SUGGESTED COUNCIL ACTIONS:

None, Informational

FISCAL and VISION NOTES:					
City Fiscal Impact Enter all that apply		**Program Impact**		**Mandates**	
City's current net FY cost	$0.00	New Program/ Agency?		Federal or State mandated?	
Amount of funds already appropriated	$0.00	Duplicates/Expands an existing program?		**Vision Implementation impact**	
Amount of budget amendment needed	$0.00	Fiscal Impact on any local political subdivision?		Enter all that apply: Refer to Web site	
Estimated 2 year net costs:		**Resources Required**		Vision Impact?	Yes
One Time	$0.00	Requires add'l FTE Personnel?		Primary Vision, Strategy and/or Goal Item #	9.3
Operating/ Ongoing	$0.00	Requires add'l facilities?		Secondary Vision, Strategy and/or Goal Item #	9.3.1 - 9.3.3
		Requires add'l capital equipment?		Fiscal year implementation Task #	

Integrated Resource Plan

2013 Update

Water & Light Staff

Recommendations and Implementation Plan

Contents

Introduction and Purpose

In August of 2013 Burns & McDonnell finished and delivered their Final Report on the Columbia Water & Light Integrated Resource Plan – 2013 Update. This 2013 Integrated Resource Plan (IRP) update for Columbia Water & Light is an update to the 2008 IRP by Burns and McDonnell. An Integrated Resource Plan (IRP) is comprised of an assessment of the future electric needs and a plan to meet those future needs. It is "integrated" because it looks at both demand side (conservation, energy efficiency, etc.) resources as well as the more traditional supply side (generation/power plants, transmission lines, etc.) resources in making its recommendations on how best to meet future electric energy needs. This 2013 IRP update outlines a plan for securing resources to meet Columbia Water & Light's energy needs in a way that will minimize the cost to customers over time and maximize consumer benefits consistent with Columbia's environmental goals and standards. The purpose of this document is to use the information developed in the 2013 IRP Update and other Department studies, assessments and documents to develop this Columbia Water & Light Staff Recommendations and Implementation Plan. This document is intended to discuss, make recommendations and propose implementation plans.

Demand

Load Forecast Methodology

Most forecasting methods use statistical techniques or artificial intelligence algorithms such as regression, neural networks, fuzzy logic, and expert systems. Columbia Water & Light has a need for long range and short range load forecasts. Long range load forecast are usually longer than one year and short range load forecast are usually from one hour to one week and is used for internal operating purposes.

Columbia Water & Light uses Econometric Regression Models for long-range load forecasting. The econometric approach combines economic theory and statistical techniques for forecasting electricity demand. This approach estimates the relationships between energy consumption (dependent variables) and factors influencing consumption as a function of weather. The Load forecast estimates are assembled using recent historical data. The primary purpose of long range forecasting is to determine our planning capacity energy production position. The primary purpose of short range load forecasting as to determine our position in the MISO Energy Market.

Columbia Water & Light uses commercially available software called Forecast Pro XE for long range forecasting. Dynamic regression models are developed that use 24 years of historical data. Different independent variables are tested to determine the best explanatory model. Weather and customer growth have the most significant impact on both demand and energy forecasts. Economic indicators, such as consumer price index, have been used to forecast customer growth; however, the current model uses historical data only. Fixed value Cooling

Degree Days (CDD) and Heating Degree Days (HDD) are used for future years. Three different degree day scenarios are modeled for each month using fixed values derived from the following – 24 year average of historical data; average of the highest ten values; and average of the lowest ten values. Peak demand and energy is then modeled for each month individually. As indicated in 5.2.2 of the IRP Update, the largest single variable impacting the accuracy of our long term load forecast is integration of net metered, including PV, generation into the Columbia Water & Light system.

Recommendations:

- Continue to use current methods and models for long range load forecasting.
- Continue to test independent variables for relevance.
- Continue to Monitor Net Metered Generation in the Columbia Water & Light system.

Community Load Assessment

All energy planning starts with an assessment of present and future energy needs. These energy needs are essentially the loads, or energy services, that define the need for energy supply. Demand Side Management has been used by utilities since the 1970's to try to influence the consumption of demand and energy by customers. The 2013 IRP Update looked at specific energy efficiency measures which were identified in the 2008 IRP to verify that these measures were achieving the results projected. The Energy Efficiency measures were based on high level data analysis so some of the projected savings were exceeded and others were not. The measures implemented were projected to have a Total Resource Cost (ratio of utility benefit/cost benefit) of greater than or equal to 1.

Loads can be grouped into residential, commercial, and industrial. Residential loads can be further broken down into space heating and cooling, thermal integrity and the appliance loads. Commercial loads also can be divided into building envelope loads and appliance loads. Unlike residential structures, where the building envelope is the primary determinant of energy needs, commercial buildings are usually dominated by their appliance load. Industrial electric and thermal loads are nearly entirely defined by the industrial process with building envelope loads being, in many instances, insignificant. The greatest numbers of energy efficiency measures recommended in the 2008 IRP were most applicable to the residential sector. These measures resulted in the following programs:

1. Home Performance with Energy Star
2. Enhanced Home Performance with Energy Star Programs
3. Commercial Lighting rebate
4. Commercial AC rebate
5. HVAC Tune up (Add refrigerant to undercharged AC system, remove refrigerant, increase blower speed due to low evaporative air flow)
6. Increase duct size due to lower evaporator air flow
7. Industrial machine drive retrofit

The selection of these programs was a result of a 2006 Saturation Study which Columbia Water & Light had participated with other utilities. None of these recommendations were specific to Columbia Water & Light data. It was strongly encouraged during the 2008 IRP process for Columbia Water & Light to complete a customer load assessment due to the city demographics of high rental population. To date, Columbia Water & Light has relied on other Appliance Saturation and Energy Efficiency Data available, but to further Columbia Water & Light's DSM mission to target specific action items/programs (services) a Community Load Assessment needs to be completed.

Customer Load Composition

To the extent possible, it is useful to have a snapshot of the appliance and equipment inventory in the Columbia Water & Light service territory. The term generally used for data of this type is "appliance saturation." At the most basic level, this means estimates of the percentage of customers who have one or more of an appliance (e.g. for residential customers, room air conditioners versus central AC). Building structure analysis, thermal integrity of the building envelope is also critical. Customer behavior and attitudes toward energy efficiency and renewable energy can also be assessed during a community load assessment. For a more generic approach to energy efficiency programs, high-level data can be obtained from EIA surveys and reports which we have utilized. However, to develop and implement programs which will have the greatest results specific to Columbia demographics a local study needs to be completed. For the residential market, this is typically done by looking at the market share of Energy Star labeled products. If resources allow, more specific information about the types, vintages and efficiency levels of equipment in homes or facilities can be gathered through surveys and samplings of onsite visits. This level of investigation can be costly, but if the effort is focused on your highest energy users, the benefits may outweigh the costs.

It was recommended in the IRP for Columbia Water & Light to gain additional information from customers via the Columbia Water & Light website, asking specific questions about energy efficiency programs, appliances etc. The result of this effort provided very little return responses. In another attempt to gather data on appliance purchases, Columbia Water & Light worked with one of the local retailers to gather information about major appliance purchases with zip code information. This was a collaborative effort with a regional energy efficiency association. The data was not specific enough for our needs. The retailer coding did not allow for granular information. The most promising effort of collecting and analyzing data has been with the use of GIS mapping. Columbia Water & Light staff has worked with the GIS staff to map participants of existing programs. The mapping has allowed better analysis looking at the achieved energy efficiency gains and the specific retrofits of select neighborhoods and housing demographics. This data has allowed us to identify customers to approach for program participation. Based on our findings of the mapping and energy efficiency analysis, a marketing campaign was launched for specific areas/housing demographics to achieve greater customer participation. The marketing efforts targeted specific locations including the level of granularity of potential energy savings, which could be achieved by program participation, returned very little responses. Staff continues to review the GIS potential allowing us to look specifically at age, aggregated energy usage and potential savings for those specific demographics. In energy planning, it is critical to start with a good understanding of the energy loads that are driving the need for supplies.

Distribution Network

Columbia Water & Light currently operates its electric system at three different voltage levels 161 kV, 69 kV and 13.8 kV. Thirty miles of 161 kV transmission lines serve as Columbia Water & Light's access to the Bulk Electric System. Five 161 kV to 69 kV transformers distribute power to forty miles of 69 kV sub transmission lines. Twenty station class transformers with a combined capacity of 410 MVA serve to create Water and Light's distribution system at the 13.8 kV level. The 13.8 kV systems currently has over 287 miles of overhead and 508 miles of underground conductors used to distribute power to Water and Light's over 47,000 Customers. Even with 410 MVA of transformation capacity, Water and Light has difficulty serving its peak loads under all stage one contingency events. This was proven this past summer when Hinkson Creek T1 suffered a catastrophic failure. While no customers had to go without power, except for the initial outage caused by the failure, this event highlighted some of the deficiencies in Columbia Water & Light's distribution system.

Columbia Water & Light currently uses a blend of redundancies to serve its load. Spare transformation capacity at its substations combined with spare feeder capacities in its distribution system typically allow Columbia Water & Light to survive the loss of any one of its station class transformers without having to shed load. The events of this summer proved that load growth in the central and southern portions of Columbia Water & Light's service territory have stretched the spare capacities to their limits. Columbia Water & Light has implemented a traditional SCADA system with remote monitoring and control of critical assets from the Columbia Water & Light control center. Critical assets currently monitored and controlled via SCADA include substation transformers, substation relays, and substation feeder breakers. Breakers at the power plant are also monitored via SCADA but are manually operated. Columbia Water & Light has load tap changers on most substation transformers but they are not remotely operable. Columbia Water & Light has also deployed some intelligent devices on select feeders outside of the substation such as some locally controlled variable capacitor banks that adjust to local load conditions and some capacitor banks that can be remotely operated through a one-way radio switch.

Recommendations:

- Use a customer outreach program to populate an appliance load model of our existing community energy loads. This model will focus on modeling the non-plug in loads and some building envelope properties.
    - Use this information to verify the performance of our existing energy efficiency programs or redesign current and/or add new programs.

- Develop a model of our existing distribution system to be used in conjunction with an accurate load model.
  - Use this model to design future expansions to the distribution system.

Implementation:

- Develop a customer outreach program with the goals of program education, program marketing and completing a Community Load Database.
  - Estimated cost $100,000.
- Development Scope of Work and issue an RFP for Distribution Network Model.
  - Estimated cost $150,000.

Energy Efficiency Programs

Utility sponsored Energy Efficiency Programs would seem to conflict with the usual business goal of selling more units. While energy efficiency measures have a technical potential, the extent that energy efficiency measures are actually achieved is often altered by the customers desire to take some of the efficiency benefits as increased comfort. In determining whether there is sufficient public purpose behind the expenditure of public money, Missouri courts apply the primary effect test, which is the primary intent of the public expenditure should be to serve a public purpose. Our existing rebate and incentive programs operate under the justification that the utilities benefit/cost ratio was greater than 1 and a majority of the benefit was gained by utility. There are various methodologies used to value the benefit of Energy Efficiency programs. Total Resource Cost analysis (TRC) was the approach used in the IRP which identifies the benefit to the utility (avoided cost) over the cost of implementing the retrofit. The ratio must be greater than 1. Residential programs implemented have a TRC of 1 or greater.

The only program not meeting the criteria of a TRC greater than 1 is the Commercial AC rebates program. The AC rebates were purposefully set higher than the prescribed incentive in the 2008 IRP due to the "Triple Net Lease" structure which is commonly used in Columbia. This landlord tenant relationship typically requires tenants to replace the AC units. Incentivizing a commercial tenant to replace an AC unit without knowing their return on investment has been difficult. The IRP update suggests creating more value to the AC rebate program. A split incentive program should be reviewed.

Energy Efficiency Tracking

Energy Efficiency Tracking software programs are expected to increase customer engagement by streamlining the enrollment process with a customer friendly web portal. With these programs customers will have the ability to access their program process and follow progress in real time. These programs should also reduce the amount of questions currently handled by our administrative staff. Columbia Water & Light has issued an RFP and evaluated the responses for this service. We have reviewed seven proposals from the RFP, we have decided to recommend CakeSystems as the selected vendor. The system offers the functionality we need at a very competitive price. Their proposal is $32,500 annually with a $97,500 setup price with the first year's annual fees included in the setup fee. This system will track customer program timelines and e-mail prompts sent when program eligibility is close to expiring. In our current system customers have let deadlines pass that resulted in missed rebate opportunities. Contractors for HPwES programs and staff have to enter data twice since the Home Energy Score modeling program is web based. CakeSystems offers an API to Home Energy Score which eliminates the double entry and generates adhoc reports for our Efficiency Score. This system should make our data collections effort more efficient, accurate and allow the Home Performance contractors to spend less time entering data.

Recommendations:

- Continue to work with all collaborative partners on greater customer outreach and education. While streamlining the program and associated costs.
- Create a certified contractor's list which receives an incentive from the utility for selling the upgrade to the tenant versus continuing the contractor making the same repairs time and time again.

Implementation:

- Develop new or increase funding for Energy Efficiency programs resulting from Customer Outreach Program and resulting load model.
    - Estimated cost $150,000.
- Implement the customer outreach plans created by the Energy Educator.
- Coordinate the efforts and marketing plan created by the CMCA Marketing assistant to make Enhanced Home Performance with Energy Star more accessible.
- Contract with CakeSystems for Energy Efficiency Tracking Software.
    - Estimate Cost $95,000 1st year Start up, $32,000 per year ongoing.

Efficiency Score

The Home Energy Score is a quick and easy to use tool. The concept behind the Home Energy Score (HES) is for it to be similar to a vehicle's mile-per-gallon rating. The HES can allow homeowners to compare the energy performance of different homes. It also provides suggestions for improving a homes' efficiency. The HES is established with Building Performance Institute qualified assessors that gather the information needed to assess a home in one short site visit. This low-cost, high value assessment can be provided as a stand-alone service or as an add-on to a home inspection or comprehensive energy assessment. Columbia Water & Light was one of the first of 10 partners to assist the Department of Energy roll out of the Home Score.

Columbia Water & Light has been working with other stakeholders and has created the Efficiency Score, based off the modeling created by the Department of Energy for the Home Score. The Efficiency Score is a little more appealing to the homeowner because it allows a home to be compared against a house of similar size or against itself providing a scale of 0 – 100 % efficiency. This type of score design and interpretation is commonly associated with the Energy Guide found on refrigerator or freezers. A Commercial Energy Score is also being developed and CW&L is a pilot utility for DOE assisting with the roll out.

Recommendations:

- Finalize development of the Efficiency Score.
- Develop and execute an program acceptance plan.

Implementation:

- Marketing of Efficiency Score.
    - Estimated Cost $20,000.
- Use on the multiple listing service for rental property.
- Work with the City's Office of Neighborhood Services for rental property acceptance.
- Include the Efficiency Score in the City's GIS system.
- Expand Enhanced Home Performance with Energy Star to include Efficiency Score.
- Incorporate the Efficiency Score on the Mid Mo Housing website which is a collaborative effort of the University of Missouri, CMCA, Housing Authority and City Departments, including the Health Department and Office of neighborhood Services.

Building Codes Coordination

Building energy-efficiency codes have received considerable attention lately because of the energy-savings opportunities they present. Some recent reports have estimated that upgrades to building energy codes could offset as much as a third of all electricity consumption growth nationally through 2025. Columbia Water & Light's only incentive for new construction is Energy Star Homes, which once all of the 8 recommended building code changes have been implemented, will be less efficient than the new code. Support of new construction programs should focus to incentivize projects that can exceed current building codes. Programs that incentivize only meeting current codes risk diverting resources from other traditional energy-efficiency opportunities and the possibility arises that savings from traditional energy-efficiency programs could also be reduced.

New Construction Programs for Residential (NCPR) can provide incentives for energy-efficient new construction for all types of residential construction projects including single family homes as well as multi-family buildings. Examples of potential incentives beyond the building code are; ground source heat pumps, embedded LED lights, heat recovery, energy efficient appliances and PhotoVoltaics.

New Construction Programs for Commercial/Industrial businesses (NCPCI) can provide assistance when incorporating energy-efficiency measures into the design, construction, and operation of new and substantially renovated buildings. These incentives are for the purchase and installation of energy-efficient equipment that reduces electric energy consumption in new and substantially renovated buildings.

Recommendations:

- Eliminate Energy Star Home rebate from current Rebate and Incentive Programs.
- Create a New Construction Program for Residential and Multi-Family.
- Create a New Construction Program for Commercial/Industrial.

Implementation:

- Design of NCPR and NCPCI.
  - Estimated Cost $200,000 for program incentives.

Financing Programs

Financing an energy efficiency retrofit can often be the greatest barrier to customer participation in making improvement. The current Columbia Water & Light Loan does not necessarily fit the need for each customer. Columbia Water & Light staff has been aware of this barrier and are seeking methods to increase customer engagement.

Home Energy Affordability Loan (HEAL)

HEAL is a program developed by the Clinton Climate Initiative to reduce energy consumption. HEAL engages not only the employer but offers the employees an opportunity to learn about energy efficiency in a similar manner as employees learns about health and safety issues.

Property Assessed Clean Energy (PACE)

PACE is a program offered to extend the payback period of an energy retrofit for commercial properties which is offered as a loan but payment of the loan is recovered via taxed assessment and paid on customer personal property tax over a 20 year term. City of Columbia could develop a program similar to PACE but offer different finance mechanisms. The City and County need to work cooperatively on this program to engage local lending institutions.

Pay As You Save (PAYS)

PAYS is a financing model that allows home or building owners to undertake energy efficiency or renewable energy retrofits with no upfront payment, and to pay the costs over time on their utility bill. Payment responsibility can be transferred to new building occupants or owners when the first borrower moves away. This approach unlocks energy efficiency savings for consumers – enabling ongoing energy savings for families who may not be able to afford the upfront costs for energy efficient retrofits. PAYS programs are designed so that energy bill savings are roughly equivalent with the loan repayment, thereby offsetting the energy efficiency investment cost to home or building owners.

Columbia Water & Light Provided Loan

Columbia Water & Light loan programs give qualified electric customers an energy efficiency loan option. Interest rates are set based on the payback period – 1% for repayment in three years; 3% for repayment in five years; and, 5% for repayment in 10 years. The Energy Efficiency Loan program was envisioned as a revolving loan fund. As of the end of fiscal year 2013, the loan program has achieved the revolving loan status as more funds are paid back into the fund than are withdrawn. At the end of FY13, there are 810 outstanding with a total value of $4,986,228. Funds available for loan stand at $813,906.

Recommendations:

- Use the City of Columbia and Boone Electric as employers to pilot a HEAL program.
- Develop a program similar to what PACE offers.
  - Create a Boone County Clean Energy Board to enact this program.
- Continue offering low-interest rate energy efficiency loans to qualified customers.
- Incorporate and promote Photovoltaic programs in our loan program.

Implementation:

- Approve authorizing ordinances to make HEAL available to City of Columbia, Boone Electric and its employees.
  - Estimated Cost for initial loan funding $100,000.
- Develop a Scope of Services and issue an RFP for a program financing mechanism similar to what PACE offers.
  - Estimated Cost $80,000.
- Coordinate with Boone Electric, develop PACE similar program for consideration by Boone County.
- Develop a Columbia Water & Light Sponsored PAYS program.
  - Estimated Cost for initial loan funding $100,000.
- Create PV loan program for approval.
  - Estimated Cost for initial loan funding $250,000

Load Modifying Resources

Load modifying resources (LMRs) is Demand Response (DR), identified to MISO for planning purposes and managed by the electric distribution utilities (EDUs). LMRs are normally dispatched by EDUs and MISO may call on LMRs during emergencies.

MISO has two general categories of demand response, DRR Type I and DR Type II resources that can directly participate in MISO markets. Type I and Type II resources are dispatched by MISO. DRR Type I is a "block" type DR resource that:

- Generally capable of a single specified reduction.
- Modeled similar to a generator.
- Can offer as energy, reserves
- Can be a capacity resource.
- Must be directly capable of receiving dispatch instructions from MISO

DR Type II is a "variable" type DR resource that:

- Generally capable of a range of specified reduction.
- Modeled similar to a generator.
- Can offer as energy, reserves
- Can be a capacity resource.
- Must be directly capable of receiving dispatch instructions from MISO and meeting set point instructions.

Initially the Columbia Water & Light Load Management programs were designed to only respond to Columbia Water & Light load signals and looked at load management solely as a peak load reducing program. The current focus for Demand Response programs is the ability to respond to regional load and cost signals. Prior to the inception of the energy market in 2005 Columbia Water & Light's load management program was designed based on the value of capacity in the range of $5 to $6 per kW month. Since the inception of the energy market, the load management program has been costing the electric utility significantly more than the value the market set for capacity. Looking at the discounted summer rate that load management customers receive, and not including material costs or personnel, the load management program costs the utility the equivalent of $3.56 per kW month for projected capacity reduction. Columbia Water & Light will be long on capacity for several years even if the amount of projected load management reduction were excluded. In addition, the current cost of market capacity is around $1.00 per kW month (prior years were significantly less). Columbia Water & Light has been approached with offers of $2.50 to $3.00 per kW month for capacity in the 2016 through 2021 period. Columbia Water & Light needs to redesign the load management program into a demand response program representing the value for participating in regional demand response programs. Programs should continue customer engagement and change incentive structure presently offered.

Recommendations

- Develop demand response program to replace the current load management program.
- Monitor Energy Services Company (ESCO) participation and solicitation of CW&L customer engagement (energy efficiency programs, utility account/bill management and payment).
- Consider ordinance for ESCO participation in Columbia as it relates to Demand Response customer engagement and aggregation of loads.
- Develop Key Account programs to offer similar service or better service offerings of ESCO

Implementation

- Change policy regarding adding new requests for load management program.
- Design Columbia Water & Light's programs and perform equipment retrofits to meet requirements for participation in Regional Demand Response programs.
    - Estimated Cost $160,000.
- Determine market potential for Demand Response program and customer incentives. Conduct a market assessment; customer attitude survey and focus group session.
    - Estimated Cost $30,000.

Street Lighting

In recent budget years the payment structure for the funding of street lighting has been changed. The current arrangement is for the General Fund to cover the cost of energy for operation and maintenance. This approach leaves the capital cost of installation to be funded by the Columbia Water & Light Revenue funds. Future lighting technology improvement decisions will require an operating cost vs. capital cost evaluations to be made.

Recommendation:

- Have a single department responsible for all street lighting cost to make future evaluation decisions accurate and transparent.

Implementation:

- Consolidate all street light funding responsibilities into Columbia Water & Light's budgets.
    - Estimated Cost $536,000.

Supply

Renewable Energy Portfolio

In November 2004, the citizens of Columbia approved a renewable energy ordinance for the power supply portfolio. The ordinance mandates Columbia Water & Light to purchase increasing levels of energy from renewable resources starting in 2008. Current renewable energy resources include Wind, Photovoltaic, Landfill Gas Generation and Biomass. Columbia Water & Light issues an annual report detailing renewable ordinance requirements and performance, below is a summary.

Year	%Req	%Del
2008	2	1.7
2009	2	4.3
2010	2	5.0
2011	2	5.4
2012	2	7.9
(Est.) 2013	5	7.0

Net Metering

Columbia's Net Metering Ordinance complies with the State Statute. Columbia Water &Light offers net metering to customers wishing to install renewable energy at their residence or business up to 100 kW. Columbia Water & Light offers customers a rebate of $500 per KW installed. With Columbia Water & Light's Net Metering Policy:

- All state laws are complied with or exceeded.
- Columbia Water &Light allows customers to rollover full retail value (approximately $0.10/kWh) to the next month for excess energy.
- After 12 Months (March billing) any carryover credits are removed.
- This allows for a more economical sizing of solar installations to be matched to annual electric loads rather than to the lowest electrical consumption month.
- Only utility with annual (12 month) true-up for net metering.
- No meter charges or other installation fees.

Community

The City of Columbia is participating in the National Solar Initiative Program offered by DOE, taking advantage of the National Renewable Energy Labs Technical Assistance Program to develop an understanding of Community Solar. The concept of Community Solar allows for a solar generation system to be built and shares of that system be sold or leased to individuals that cannot readily participate or install solar at their place of residence or business. There are several models of Community Solar which will need to be reviewed and selected by Columbia Water & Light. Customer benefits for participation in the system can be virtually net metered to the customer which is allowable under current State of Missouri statutes. The future of our current Solar One program will need to be addressed upon successful development and with increasing participation levels in a community solar program.

Water & Light Developed

Photovoltaic generation has seen decreasing cost of development in the past few years. Staff feels this is a good time to budget an annual allocation for the development of photovoltaic generation on Columbia Water & Light property. The ability for future Columbia Water & Light developed photovoltaic generation to be included for community solar participation will depend on the success of the community solar program. At this time approximately half of the production cost will be reflected as a renewable energy rate impact.

Renewable Energy Purchase Power Agreements (PPA)

Columbia Water & Light released a request for proposal that required vendors to submit renewable energy proposals by early July 2013. In evaluating the renewable cost associated with these proposed resources it is important to keep focus on the total additional renewable cost remaining below the cutoff threshold outlined in Section 27-106(b) of Renewable Energy Standard of Columbia ordinances.

Bio-Fuels Development

Since 2008, Columbia Water & Light has been co-firing biomass with coal in the solid fuel fired power generation units at the Municipal Power Plant. The biomass, in the form of locally sourced wood chips, has been used to provide .5% of Columbia Water & Lights' net energy for load in 2012, and has proven to be an effective and economical way to provide renewable energy per Columbia's Renewable Energy Ordinance. Columbia Water & Light has also been active in promoting and encouraging the mid-Missouri community to develop other potential sources of bio-mass fuel. In 2012 an Initial Technical Feasibility Study for Conversion of Stoker Coal Fired Boilers to 100% Biomass Firing was conducted. The goal of this report was to evaluate the feasibility of firing agricultural-based biomass fuel pellets in a stoker fired boiler. This report was to investigate the feasibility of firing biomass fuel pellets as conditions evolve in the utility industry. CWL has tested a miscanthus derived fuel and has another test pending with corn stover and grass derived fuel. Advantages of locally produced bio-mass fuel include community and economic development benefits, reducing net $CO2$ and other emissions and keeping local power generation viable which enhances local electric system reliability.

Columbia Water & Light has invested resources to study the potential to development a community scale Biomass Combined Heat and Power (CHP) Plant at the Route B Industrial Corridor. The capacity and technology for a biomass CHP plant is typically defined by the thermal loads of the facilities it will serve and the type, availability and price of biomass fuels in the region. The objectives for this work have been to define the thermal loads that exist at potential industrial facilities, assess the availability and costs of various biomass feedstock options and determine if a generic biomass CHP plant can be developed to serve the thermal loads with the available biomass fuels.

Recommendations:

- Continue to identify the Community Solar model best suited for Columbia, identifying ownership, feasibility, community outreach, and cost of project development.

- Budget an annual allocation for the development of photovoltaic generation on Columbia Water & Light property.
- Continue to co-fire biomass in Columbia Water & Light power generation assets and work within the mid-Missouri community to develop new sources of bio-mass fuel.
- Routinely assess renewable energy market opportunities with issuance of an RFP on 2-3 year intervals.
- Investigate methods of economically increasing amount of biomass co-firing that require no or only modest changes to existing equipment.
- Finalize the cost and recommendation for the development of a biomass CHP facility.

Implementation:

- Designate the West Ash Pump station solar site as the first Community Solar Site – identifying the solar potential and the level of participation needed.
    - Estimated Cost $500,000.
- Budget an annual allocation for the development of Photovoltaic on Water & Light owned property.
    - Estimated Cost $200,000/yr.
- Work with Missouri Department of Natural Resources to conduct test burns of promising new sources of biomass fuels.
    - Estimated Cost $375,000.
- Procure new sources of successfully tested biomass fuels at commercially sustainable cost.
- Finalize a Biomass CHP Feasibility Study.
    - Estimated Cost $20,000.

Municipal Power Plant

The Municipal Power Plant (MPP) is located at 1501 Business Loop 70 E in Columbia, and has been in continuous operation since 1914. Power generated at the MPP typically supplies about 7-10% of Columbia's energy needs through the operation of four power generation systems. The MPP also contains Columbia Water & Light's main, but soon to be back-up system Control Center, and serves as the administrative headquarters for Columbia Water & Light's other power generation activities. As is typical with power generating utilities, Columbia Water & Light is required to comply with a host of federal and state environmental rules, including the Acid Rain Program, Clean Air Interstate rule, Industrial Boiler MACT Rule, Utility MATS rule, National Pollutant Discharge Elimination System, Cross State Air Pollution Rule (CSAPR), NESHAP for Reciprocating Internal Combustion Engines (RICE) and others. Some of the pollutants regulated under these rules include: CO_2, NOx, NOx Ozone, SO_2, Mercury, Lead, Dioxins, Particulate Matter, Acid Gases, and others. Columbia Water & Light will be faced with significant challenges in its own on-going efforts to remain in compliance with existing rules and new rules as they are implemented over the next several years. As a "worst case" planning condition, the IRP assumed that the solid fueled units at the MPP would be retired about 2015.

Even considering these challenges, there are significant advantageous to maintaining and operating the MPP including: increased system reliability through local generation, significant electrical generation capacity that is already owned by Columbia Water & Light, and the ability to self generate renewable energy using local resources. Due to the way the Columbia Water & Light distribution system developed during its history, maintaining local generation at the MPP with at least one of the solid fuel units will defer the need for extensive sub-station upgrades at the MPP.

Plan for Solid Fuel Units

The MPP has two solid fuel units that will require upgrades to remain in compliance with federal air pollution rules, particularly the Industrial Boiler MACT and/or Utility MATS rules by the 2015-2016 time frames. Columbia Water & Light has conducted several recent studies in preparation for these rules.

In March 2011, SEGA Engineers, delivered are report entitled "Boilers 6 and 7 Biomass Combustion and Multi-P Emissions Study." The purpose of this study was to evaluate biomass co-firing and pollution control options for the MPP. This report identified potential methods of controlling various air emissions given Columbia Water & Light's existing assets and the desire to increase the use of biomass fuels. The cumulative results of this study are summarized below.

	Low Sulfur Western Kentucky Least Cost	Low Sulfur Western Kentucky Max Cost	Low Sulfur Western Kentucky & Biomass	High Sulfur Illinois Basin	High Sulfur Illinois Basin & Biomass
Total Installed Capital Cost ($)	8,448,000	23,949,000	25,106,000	$45,473,000	$46,630,000
Total O&M ($/yr)	2,531,500	1,694,200	1,545,019	2,928,500	2,379,784
Total Annualized Cost ($/yr)	$3,298,210	$3,867,725	$3,823,544	$7,055,466	$6,611,750

During most of 2012, Lutz, Daily & Brain Engineers conducted an extensive evaluation of Columbia Water & Light's solid fuel fired systems and provided a comprehensive condition assessment report in December 2012, detailing the condition of the various systems and identifying likely repairs and upgrades required to keep those systems in service for another 10 to 20 years. The last comprehensive power plant condition assessment report for these two solid fuel unit power plant additions was conducted in the early 1980's. In general, these two solid fuel fired steam electric generating units are in good condition with the exception of some components which will need upgrading and/or replacement over the next 20 years. Below is a summary of the costs which have been identified as being needed for either upgrading or replacing components over the next 20 years.

	Unit 6	Unit 7	Common
Maintenance & Capital Project	$6,475,000	$7,734,000	$1,678,000

In November 2012, Lutz, Daily & Brain delivered a report entitled "Phase I Initial Technical Feasibility for Conversion of Stoker Coal Fired Boiler 6 to 100% Biomass Firing" which identified issues concerning converting the existing Boiler 6 system to 100% biomass fuel. Some of the principle conclusions from the report follow:

- Burning agricultural based biomass pellets in Boiler 6 is technically feasible, with significant modifications made to the boiler, and possible boiler capacity derating.
- Potential operating issues include increased slagging and fouling due to high alkali content and lower ash fusion temperature of the fuel.
- Higher silica and chlorine contents in the fuel could lead to increased erosion and corrosion of boiler parts.
- Upgraded fuel handling and storage equipment would be required, particularly to keep fuel out of the weather.

In February 2013, attorneys at Lathrop & Gage, provided a report covering the applicability of various federal regulations to the MPP and Columbia Water & Light assets.
Key conclusions of the report follow:

- Boilers 6, 7 and 8 are and will continue to be in the Acid Rain and CAIR programs.
- Boiler 6 is clearly subject to the Boiler MACT rule.
- Boiler 7 is on the borderline between the Boiler MACT and MATS rules.
- Conversion to 100% bio-mass fuel provides no relief to the Acid Rain or CAIR rules.
- Co-firing with bio-mass may provide some emissions limit benefits with respect to the Boiler MACT rule.

In July 2013, Lutz, Daily & Brain, delivered the last phase of the Condition Assessment report which included an updated view of Environmental Rule Compliance given inputs from previous reports and work.

Some of the key inputs given were that Boiler 6 – Turbine 5 would be retired, and that the following Air Quality Control (AQC) systems were being considered for Boiler 7 – Turbine 7: Over Fire Air (OFA), Selective Non Catalytic Reduction (SNCR), Dry Sorbent Injection (DSI), Activated Carbon Injection (ACI), and Flue Gas Recirculation (FGR). Some key findings from the review include:

- Boiler 7 is on the borderline between Boiler MACT and MATS rules.
- Firing at least 20% bio-mass would categorize Boiler 7 as a "wet biomass-fired boiler."
- Area Source versus Major Source boilers are treated differently with respect to Boiler MACT, with Area Source being most beneficial to Columbia Water & Light.

- An 80% reduction of SO_2 emissions will likely be required.
- A 60% reduction of NO_x emissions will likely be required.

Much of the basic 'due diligence" type work required to make informed decisions concerning the future of the solid fuel fired units has been completed.

Plan for Natural Gas Fuel Units

The MPP has two natural gas fired power generation units. Historically, these units have operated infrequently as the price of natural gas has traditionally been higher than solid fuel. However, the recent increases in North American natural gas production and the resulting drop in natural gas prices, have presented opportunities to change the way Columbia Water & Light uses these assets to maximize their benefit to the utility. Boiler 8 is Columbia Water & Light's largest steam generating unit and uses natural gas for fuel. Boiler 8 can be used for both base-load and peak-load applications. In response to low natural gas prices and pending implementation of the Cross States Air Pollution Rule, Columbia Water & Light had SEGA Engineers provide a study entitled "Boiler 8 NOx Reduction Study," delivered in April 2012, which identified methods and general cost estimates for making Boiler 8 more useful in the current low gas cost environment.

Reciprocating Internal Combustion Engines (RICE) Plans

Columbia Water & Light currently has 9 diesel fuel fired engine-generator sets located throughout Columbia which are used as back-up sources of power for various large industrial customers, and can be used for Columbia Water & Light system peak shaving or emergency power purposes. These units have a total capacity of 13MW, are classified as "limited use" units and are allowed to operate up to 100 hours per year. Recent federal rules regarding RICE units, will not allow for the expansion of their use.

Columbia Water & Light owns and operates the Landfill Gas Plant located at the Columbia Landfill. Methane produced by the landfill is used in reciprocating engine generator sets to produce power. Each generator is 1 MW in size, and there are currently three (3) units in service. The Landfill Gas Plant produces about 1% of Columbia Water & Light's energy and is a part of the Renewable Energy Portfolio.

The IRP proposed using relatively large (~ 9MW) natural gas fired reciprocating engine-generator sets to provide for the future capacity and energy needs for Columbia. These would be locally sited units would be constructed, owned, and operated by Columbia Water & Light. These units are typically used for short durations for peak load type conditions due to their ability to be on and off-line quickly. The IRP indicates that this type of unit could be needed about 2019, depending upon the final disposition of the MPP's solid fuel units.

Recommendations:

- Continue to monitor developments in the implementation of air and water pollution rules.
- Continue to monitor industry developments for techniques for controlling air and water pollutants.
- Identify methods to improve value of existing units with respect to the MISO energy and capacity markets, and Columbia energy and reliability needs.
- Implement Low NOx upgrades to Boiler 8.
- Develop low cost reliable supplies of natural gas.
- Continue to maintain and operate existing RICE units.
- Continue to monitor supply of methane produced at the Columbia landfill.

Implementation:

- Develop a recommendations report for future of solid fuel fired units.
  - To be completed in first quarter of calendar year 2014.
- Continue operation of Gas Turbine #6.
- Fund capital projects to make upgrades to Boiler Turbine #8.
  - Estimated Cost $2,500,000.
- Develop overall MPP air and water compliance strategies.
- Develop a financial model of MPP operating, upgrade, and related CWL system costs.
- Add an additional engine-generator set at the Landfill Gas Plant when adequate supplies of methane are produced by the Landfill.
  - Estimated Cost $1,600,000.
- As the need for additional CWL capacity resources develop, conduct feasibility and site selection studies for potential large RICE natural gas fired generating unit.
  - Estimated Cost $60,000.

Columbia Energy Center

The Columbia Energy Center (CEC) is a simple cycle combustion turbine plant located in northeast Columbia near Columbia Water & Light's Bolstad substation. The facility contains four natural gas fired 36 MW gas turbines for a total plant capacity of 144 MW. The plant typically operates in the summer months during times of peak load. The plant was constructed in 2001 by Ameren. Columbia Water & Light purchased 25% of the plant in February 2010 and the remaining 75% of the plant in June 2011. The plant is currently operated and maintained by a contractor to Columbia Water & Light, under a contract that was inherited from Ameren. When purchased by Columbia Water & Light the plant was in its "as constructed" condition.

The IRP indicated that a possible method for meeting future Columbia Water & Light capacity and energy needs is to convert the CEC from a simple cycle plant to a combined cycle plant. A combined cycle plant would capture heat from the existing turbines to generate steam to power new steam turbines, thereby increasing electric generating capacity, while improving overall fuel efficiency. Doing so would require the installation of Heat Recovery Steam

Generating (HRSG) units to the existing turbines and the installation steam turbines and associated equipment.

A preliminary combined cycle conversion study was completed by Stanley Consultants in August 2013. The study indicated that the combined cycle idea for CEC was sound and rough cost estimates were developed. Should Columbia Water & Light desire to pursue the option further, more detailed engineering and financial analysis would be required.

Recommendations:

- Transition operation and maintenance of CEC from contract forces to Columbia Water & Light forces.
- Update and maintain CEC to good state of repair.
- Continue to monitor developments in technology for adding combined cycle to the existing plant.

Implementation:

- Update CEC controls to current standards.
    - Estimated Cost $2,500,000.
- Recruit and hire new Columbia Water & Light staff to maintain and operate plant.

Future Power Supply Considerations

The IRP indicated that perhaps the most economically effective means of meeting future capacity and energy needs would be for Columbia Water & Light to participate in a large combined cycle plant which would presumably operate at high capacity factors. Naturally, a project would have to develop within a reasonable geographical area relative to Columbia and at a time when project commercial dates closely match Columbia Water & Light capacity and energy needs.

Recommendations:

- Monitor industry landscape through Missouri Public Utility Alliance (MPUA) and other resources to identify timely large scale combined cycle projects where Columbia Water & Light participation may be practical.

Integration Issues

Virtual Power Plant

According to Wikipedia "A virtual power plant is a cluster of distributed generation installations (such as microCHP, wind-turbines, small hydro, back-up gensets etc.) which are collectively run by a central control entity. In the United States, Virtual Power Plants not only deal with the supply side, but also help manage demand and ensure reliability of grid functions through demand response (DR) and other load shifting approaches, in real time." A Virtual Power Plant (VPP) is a system that relies upon software and hardware systems to remotely and automatically dispatches and optimize generation, demand-side, or storage resources (including plug-in electric vehicles and bi-directional inverters) in a single, secure web-connected system.

As the name suggests, a virtual power plant does not physically exist as a power generator in the conventional sense. Instead, it pools a cluster of small-scale plants, using sophisticated software to operate them collectively as if it were a single large facility. In the future such virtual power plants will play a vital role in the transition to alternative sources of energy, serving to aggregate the output of countless wind generators, photovoltaic plants, biomass facilities, and combined heat and power (CHP) plants. Virtual Power Plants can be highly responsive, able to respond very quickly to surges in demand for heating or cooling, in a way not possible with traditional large scale power plants.

The utility world has changed in the last 10 years. New technologies, smart meters and smart grid concepts have made inroads into the utility space. As utilities face pressures from regulatory bodies that encourage carbon reduction with greater customer flexibility, utilities need to balance these new requirements with the financial obligations of providing reliable power at a reasonable price.

Smart Grid Study

In June of 2013 Columbia Water & Light received a report on Smart Grid Business Case from its consultant, Burns and McDonnell. The purpose of this study was to help Columbia Water & Light in determining which Smart Grid components and implementation strategies are best suited for the City of Columbia. The results of this study will be forth coming.

Electric Vehicles

Support of plug-in electric vehicle technology is consistent with our vision to a secure energy future. To meet customers' expectations Columbia Water & Light needs to fully understand and be prepared for the impact electric vehicles can have our delivery system. Columbia Water & Light recommends acquisition of an electric vehicle in order to fully understand the possibility, performance and issues with this technology. While a majority of the energy supplied to the Columbia Water & Light system comes from a power plant that burns coal, studies have shown that the airborne power plant emissions released to charge a new electric vehicle is roughly half the tailpipe emissions released by a new gasoline power vehicle.

Recommendations:

- Begin placing a greater emphasis on educating customers about the ongoing challenges and emerging opportunities in the Virtual Power Plant and Smart Grid Industry.
- Begin to gauge customer interests in information, technologies and programs that incent behavior change, offer savings potential, and reduce utility cost of service.

- Integration of GIS data to existing OMS and Asset Management Systems.
- Continue to develop the system and infrastructure need to model operate and control Columbia Water and Light resources from a central control facility.
- Evaluate various Distribution Automation (DA) technologies.
- Acquisition of an electric vehicle in order to fully understand the possibility, performance and issues with this technology.
- Conducting a thorough cyber security threat and vulnerability evaluation and gap analysis.
- Finalize Smart Grid Report and Recommendations.

Implementation:

- Purchase of New EMS is scheduled for new central control facility recently completed.
  - Estimated Cost $1,500,000.
- Transition of System Operations into new central control facility.
  - Estimated Cost $400,000.
- Present Final Smart Grid Report to Advisory Board and Council.
- Budget for the acquisition of an electric vehicle and charging station.

Rate Structure

Section 5.3.8. from the IRP Update recommends that "(Columbia Water & Light) should continue to review its rate structure to review the impact of declining sales from DSM and the potential impact due to increasing use of net metered solar PV". Before discussing specific issues related to rate structure and impacts on revenue, the following general overview provides information on each of the current electric rate classifications of Columbia Water & Light.

Columbia Water & Light utilizes four primary electric rate classifications – residential, small general service, large general service and industrial. Each rate classification has additional rate variations depending on customers meeting defined requirements. The following table shows the percentage breakdown of total customers, total kWh usage, and total revenue for each rate classification in FY13.

	Percent of Total Customers	Percent of Total kWh Use	Percent of Total Revenue
Residential	86%	36%	41%
Small General Service	12%	9%	10%
Large General Service	2%	31%	30%
Industrial	0%	24%	19%

Note - Industrial Class is 1/10th of 1% of Customers

As can be seen from the table above, there are differences in the percent of kWh use versus the percent of revenue collected. Columbia Water & Light uses cost-of-service analysis which utilizes coincidental and non-coincidental cost allocation to determine the revenue requirement necessary for each rate classification. Because the Industrial class has a more balanced annual usage pattern, the utility's cost to serve those customers is the least of any class and is reflected in the rate structure and the revenue collected compared to kWh used. The following is a general overview of each rate classification.

Residential

Residential customers pay a monthly base charge and a per kWh usage charge. The base charge should cover costs associated with customer billing (such as meter reading and billing) plus some distribution related costs. If the base charge is set at the proper level, the distribution cost not charged through the base charge would represent approximately two cents per kWh of the usage charge.

During the summer season (June through September), Columbia Water & Light utilizes an inverted block rate structure for residential customers. The first 750 kWh's of usage is at the lowest price. Usage between 750 kWh's and 2,001 kWh is charged a rate that is 35.3% higher than the charge for the first 750 kWh. The following summer information is the average for FY10, FY11, and FY12.

- 41.2% of kWh usage and 44.5% of kWh revenue occur in the summer period.
    - 59.3% of kWh usage and 51.6% of kWh revenue is for usage in the first 750 kWh block
    - 35.4% of kWh usage and 41.7% of kWh revenue is for usage in the second kWh block
    - 5.3% of kWh usage and 6.7% of kWh revenue is for usage above 2,000 kWh
- The total load management discount for residential customers is $233,000 per year

During the non-summer season (October through May), customers that do not have electric heat or high-efficiency heat pumps are charged a one-step inverted block rate. All usage above 750 kWh's is charged at a rate 15.3% higher than the first 750 kWh's. Customers with electric heat are charged a rate that is 12% less than the first block for all usage above 750 kWh. Customers with a qualifying high efficiency heat pump are charged a rate that is 15% less than the first block for all usage above 750 kWh. The following non-summer information is the average for FY10, FY11, and FY12.

- 58.8% of kWh usage and 55.5% of kWh revenue occur in the non-summer period.
    - 70.6% of kWh usage and 71.0% of kWh revenue is for usage in the first 750 kWh block.
    - 29.4% of kWh usage and 29.0% of kWh revenue is for usage above 750 kWh.

Small General Service (SGS)

This classification is used for small commercial customers that do not exceed 25 kW during the summer season. As with residential customers, SGS customers pay a monthly base charge and a per kWh usage charge. There are two different base charges – one for customers with single-phase service and a higher charge for customers with three-phase service. Demand (kW) information is collected on above half of the Small General Service customers but a demand charge is not assessed.

The Small General Service classification has a single-step inverted block rate for summer kWh usage. All usage above 1,500 kWh is billed at a rate that is 35.3% higher than the first block. The following summer information is the average for FY10, FY11, and FY12

- 38.9% of kWh usage and 43.1% of kWh revenue occur in the summer period
    - 34.8% of kWh usage and 34.6% of kWh revenue is for usage in the first 1,500 kWh block
    - 43.6% of kWh usage and 51.5% of kWh revenue is for usage above 1,500 kWh
- The total load management discount for small general service customers is $23,200 per year

During the non-summer months, all kWh usage is billed at the same rate as the first 1,500 kWh of summer usage, except for electric heated or high efficiency heat pump customers. Customers with electric heat are charged a rate that is 10% less than the first block for all usage above 1,500 kWh. Customers with a qualifying high efficiency heat pump are charged a rate that is 15% less than the first block for all usage above 1,500 kWh. The following non-summer information is the average for FY10, FY11, and FY12

- 61.1% of kWh usage and 56.9% of kWh revenue occur in the non-summer period

Large General Service (LGS)

This classification is for customers that exceed 25 kW during the summer season but do not exceed 750 kW. Customers in this classification pay both a demand (kW) charge and an energy (kWh) charge but do not pay a base charge. The summer demand charge is 25.1% higher than the non-summer demand charge and the summer energy charge is 15.1% higher than the non-summer energy charge. There are no variations in either demand charge or energy charge except for the seasonal difference. Approximately 38.9% of the LGS kWh usage and 40.5% of revenues from the LGS class occur during the summer season. The rate structure LGS utilizes is designed to reward customers that maintain higher load factors. The customers' load factor is the ratio of the customers actual kWh to the potential kWh usage based on actual kW and time. Typically, LGS customers pay a lower average cost per kWh as their load factor increases. The following table is based on annual load factor and shows the percentage of customers that fall within each ten percent load factor range as well as the associated percentage of kWh usage, percentage of revenue to the utility and average cost per kWh. The table is for LGS customers that do not participate in the load management program. Because the annual load factor is based on highest summer kW, an annual load factor greater than 100% is possible.

LGS customers that do not participate in the load management program represent 83.6% of the total LGS bills; 88.9% of total LGS kWh; and, 88.7% of the total LGS revenue. LGS customers that do participate in the load management program represent 16.4% of the total LGS bills;

11.1% of total LGS kWh; and, 11.3% of the total LGS revenue. The following table shows the same information for LGS customers participating in the load management program as the previous table showed for those customers that do not participate.

LM	≤10%	≤20%	≤30%	≤40%	≤50%	≤60%	≤70%	≤80%	≤90%	≤100%	>100%
% Bills	2.2	12.5	24.5	28.3	17.4	10.3	3.8	0.5	0.5	0.0	0.0
% kWh	1.0	9.4	20.3	24.9	19.6	18.6	3.5	0.9	1.9	0.0	0.0
%Revenue	0.6	6.8	17.3	24.3	21.0	21.7	4.7	1.0	2.6	0.0	0.0
$$ per kWh	.180	.127	.103	.091	.084	.080	.074	.081	.072	N/A	N/A

The total load management discount for LGS customers participating in the program is $50,200.

Industrial

This classification is for customers that exceed 750 kW during the summer season. The industrial rate structure is the same as the LGS structure except that the demand charge is higher and the energy charge is lower. The summer demand charge is 25% higher than the non-summer demand charge and the summer energy charge is 16.7% higher than the non-summer energy charge. There are no variations in either demand charge or energy charge except for the seasonal difference. Approximately 39.1% of the industrial kWh usage and 40.7% of revenues from the industrial class occur during the summer season.
Customers in the industrial rate class can participate in the load shedding program but the load management program is not available. The following table is based on annual load factor and shows the percentage of customers that fall within each ten percent load factor range as well as the associated percentage of kWh usage, percentage of revenue to the utility and average cost per kWh.

Industrial	≤10%	≤20%	≤30%	≤40%	≤50%	≤60%	≤70%	≤80%	≤90%	≤100%	>100%
% Bills	0.0	0.0	5.9	5.9	17.6	29.4	38.2	0.0	2.9	0.0	0.0
% kWh	0.0	0.0	1.6	1.9	10.7	26.2	51.7	0.0	7.9	0.0	0.0
%Revenue	0.0	0.0	2.7	2.4	11.9	26.6	49.5	0.0	6.8	0.0	0.0
$$ per kWh	N/A	N/A	.125	.098	.084	.076	.072	N/A	.065	N/A	N/A

Discussion – In general, because Columbia Water & Light's rate structure is designed to encourage conservation and reward efficiency, there are issues that must be monitored and addressed.

Base Charge

Columbia Water & Light's current base charge, for residential and small general service customers, is well below the level necessary to cover customer related and meter related costs. This charge should be increased to a level based on cost-of-service analysis. In addition, a base charge should be established for the large general service and industrial customers.

Revenue at Risk

Because Columbia Water & Light utilizes seasonal rates and an inverted block structure, there is a greater potential for the utility to not meet revenue requirements on an annual basis. In the past, the primary driver for revenue variations has been weather; however, customer based renewable production and energy efficiency improvements can have a significant impact on the utility's ability to meet revenue requirements going forward. Revenue is also at risk when utilities incentivize customers to reduce usage. In the short term this revenue risk would be the difference between the costs of market energy versus the energy charge to customers.

Unrecognized Expenses

In the update of the 2008 IRP, the cost of contractor incentives is not factored into cost/benefit analysis of energy conservation programs. Contractor incentives are used to build new programs but can become engrained in the program. These incentives must be recognized and phased out within a reasonable time or else factored into the overall program cost.

Net Metering Customers

Customers that install photovoltaic systems on their homes are currently being paid the full retail rate for energy that is sold back to the utility. The cost of a kWh is made up of energy cost, capacity cost and transmission/distribution cost. It is reasonable to pay a customer for energy at the utility's average cost; however, paying a customer the full retail rate places costs on other electric customers that should be borne by the customer receiving the service.

Charging KW vs. KWh

The most equitable method of charging customers is to separate demand and energy charges. The demand charge more closely reflects the impact of a customer on the electric system and charges can be assessed accordingly. If Columbia Water & Light went to smart metering, it would be possible to develop rate structures that charge demand and energy for all customers. Currently, none of the approximately 41,000 residential customers have metering capable of collecting demand readings. There are approximately 3,000 commercial customers that do not have metering that can collect demand readings.

Result Tracking

Social trends, economic realities and regulatory demands are driving significant growth and sophistication of energy efficiency (EE) programs. Organizations are challenged with creating solutions that meets requirements unique to each jurisdiction, utility and IT environment. One important element of this process is to efficiently manage the process and accurately collect the information needed to determine program results. In an effort to achieve this goal Columbia Water & Light has issued and RFP for an EE result tracking system to achieve these goals.

Recommendations:

- Increase base charge, for all customer classes, to the level recommended by the latest cost-of-service study.
- Eliminate contractor incentives after establishment of an online energy efficiency tracking program.
- Establish methodology for assessing revenue at risk from energy efficiency programs.
- Eliminate SGS classification and charge demand and energy for all commercial customers.

Implementation:

- Adjust base charge annually with required rate increase and/or revenue neutral change until recommended level is achieved.
- Develop plan to phase out contractor incentives and phase in of energy efficiency tracking programs.
- Install demand meters on the 3,000 commercial customers that do not have one.
  - Estimated cost - $850,000 for AMR meters.
- Redesign SGS and LGS rate structures to accommodate demand charges for all commercial customers while minimizing rate shock.

Budget Year Cost Phasing

2013 IRP Update Staff Plan Recommended Item	Estimated Total $	FY14	FY15	FY16	FY17	FY18	FY19+
Efficiency Score Marketing[1]	$20,000	$20,000					
CWL Community PV Pilot at W.Ash[5]	$500,000	$500,000					
Customer Outreach Program[1]	$150,000	$150,000					
Design of NCPR and NCPCI[1]	$200,000	$100,000	$100,000				
Outreach Energy Efficiency Program Funding[1]	$750,000		$150,000	$150,000	$150,000	$150,000	$150,000
Distribution Network Model[7]	$150,000	$150,000					
Energy Efficiency Tracking System[1]	$255,000	$95,000	$32,000	$32,000	$32,000	$32,000	$32,000
HEAL[4]	$100,000	$20,000	$20,000	$20,000	$20,000	$20,000	
CWL PV Loan[4]	$250,000	$250,000					
PAYS[4]	$100,000		$50,000	$50,000			
SGS Demand Meters[3]	$850,000	$200,000	$400,000	$250,000			
CWLD MISO DR Program Development[2]	$30,000	$30,000					
CWL Load Mgmnt to MISO DR[2]	$1,000,000		$200,000	$200,000	$200,000	$200,000	$200,000
CWL Developed PV[5]	$1,000,000		$200,000	$200,000	$200,000	$200,000	$200,000
PACE[4]	$20,000		$20,000				
Electric Car and Charging Station[2]	$50,000		$50,000				
MPP Unit#8 Upgrades[6]	$2,500,000	$1,000,000	$1,500,000				
LFG Gen#4[5]	$1,600,000				$1,600,000		
CEC Controls[7]	$2,500,000	$1,000,000	$1,000,000	$500,000			
New EMS[7]	$1,500,000	$1,000,000	$500,000				
MPP RICE feasibility[6]	$60,000		$60,000				
BioMass Test Burn at MPP[5]	$375,000	$375,000					
CHP Study[5]	$20,000	$20,000					
Totals	**$13,980,000**	**$4,910,000**	**$4,282,000**	**$1,402,000**	**$2,202,000**	**$602,000**	**$582,000**
		$1,265,000	FY14 Appropriations				

Category Breakdowns

Energy Efficiency [1]	$1,375,000	$365,000	$282,000	$182,000	$182,000	$182,000	$182,000
Demand Response [2]	$1,080,000	$30,000	$250,000	$200,000	$200,000	$200,000	$200,000
System[3]	$850,000	$200,000	$400,000	$250,000	$0	$0	$0
Loan[4]	$470,000	$270,000	$90,000	$70,000	$20,000	$20,000	$0
Load Totals	**$3,775,000**	**$865,000**	**$1,022,000**	**$702,000**	**$402,000**	**$402,000**	**$382,000**
Renewable Resources[5]	$3,495,000	$895,000	$200,000	$200,000	$1,800,000	$200,000	$200,000
Non-Renewable Resources[6]	$2,560,000	$1,000,000	$1,560,000	$0	$0	$0	$0
System[7]	$4,150,000	$2,150,000	$1,500,000	$500,000	$0	$0	$0
Supply Totals	**$10,205,000**	**$4,045,000**	**$3,260,000**	**$700,000**	**$1,800,000**	**$200,000**	**$200,000**
Totals	**$13,980,000**	**$4,910,000**	**$4,282,000**	**$1,402,000**	**$2,202,000**	**$602,000**	**$582,000**

Integrated Resource Plan
2013 Update

for the

Water and Light Department
City of Columbia, Missouri

Project Number 67546

2013

Burns & McDonnell
SINCE 1898

Burns & McDonnell
SINCE 1898

August 6, 2013

Mr. Tad Johnsen
General Manager
CWL
701 East Broadway
Columbia, MO 65205

CWL Integrated Resource Plan
Final Report on the Integrated Resource Plan-2013 Update
Project: 67546

Dear Mr. Johnsen:

The attached "Final Report on the CWL Integrated Resource Plan-2013 Update" is provided in accordance with the authorization provided by CWL for Burns & McDonnell to provide an update to the 2008 Integrated Resource Plan (2008 Study) that provided direction for supply side and demand side resource development. The overall objective of the analysis was to review the supply side resource changes since the 2008 Study and impacts from existing demand side programs offered by CWL to determine if any revisions were warranted to the more attractive supply side options in meeting CWL forecasted demand and energy requirements recommended in the 2008 Study.

APPROACH

Information was requested from CWL to update the current supply and demand side conditions. This data included the major issues of load forecast, changes in its supply side resources, RPS requirements and existing demand side programs. The load projections were then combined with the available resources to determine if and when the existing resources would be inadequate to meet the load projections. A review of both the capacity (MW) capabilities and the energy (MWh) sources to meet projections was considered.

Assumptions on a variety of inputs to the analysis were developed and provided for review by CWL. The assumptions included fuel and market energy price forecasts, operation and maintenance costs for existing resources, financial parameters, and a variety of other assumptions. Burns & McDonnell developed supply side resource options for consideration and reviewed the projected capital, operations and maintenance costs with CWL.

The information about the current DSM programs offered by CWL included participation levels and demand and energy impacts from the programs. No new programs were considered to be added in the 2013 Update. Review of expected results and benefits were developed based on CWL historic information.

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An analysis of potential supply side resources to meet the load projections was performed. This analysis was done to establish the attractive future considering the load forecast being met with supply side resources while meeting the RPS requirements. Expected results from the current offered DSM programs were developed and considered in the review of supply side needs.

Supply Side

Supply side options were selected for consideration by Burns & McDonnell based on its experience with current available options. CWL system capacity requirements were considered with allowance of a reserve margin of 14 percent of peak load less firm purchases. The resource options were developed considering the expected deficits of capacity for CWL and typical sizing for the options.

For supply side options, Strategist was used to select the MW amount and timing of resource options to add and satisfy the utility's annual requirements over the study period. The program iterates to arrive at optimal portfolios for the options considered. Due to current environmental policies, natural gas fired and renewable alternatives were the only resource options considered.

Demand Side

The existing DSM programs being offered by CWL were reviewed. The load forecast provided by CWL included the effects of ongoing DSM programs which were considered to continue at their historic levels. The 2013 Update did not consider any new programs but directed efforts to identify more CWL specific information on participation levels, actual demand and energy reductions achieved and expected reductions of demand and energy based on estimates of CWL end use inventory.

SUMMARY OF CONCLUSIONS

Based on the analysis of CWL's system contained in the attached report and factors affecting the electric utility industry, Burns & McDonnell offers the following conclusions for consideration by CWL:

1. The existing DSM programs appear to be providing positive benefit with regards to CWL's load requirements and should be continued.

2. CWL should continue to work with the City to improve the application and enforcement of more efficient building codes across the commercial and residential sectors. The current situation where CWL attempts to entice building owners to improve their building's efficiency through use of CWL incentives after they are constructed is not a good use of CWL capital or human resources.

3. CWL's supply side expansion options are essentially limited to natural gas fired and renewable energy resources. The need to add these resources, with the expected load forecasts, does not occur until approximately 2019. CWL should monitor the cost of capacity from the area market to determine if the actual construction of resources is more economical.

4. CWL should continue to review its rate structure to review the impact of declining sales from DSM and the potential impact due to increasing use of net metered solar PV.

We look forward to meeting with the Task Force to discuss the analysis of the information discussed in the attached report. Should you have any questions or comments, please do not hesitate to call.

Sincerely,

Jeff Greig
General Manger

Kiah Harris, PE
Project Manager

Final
Report
on the
Integrated Resource Plan-2013 Update

PREPARED FOR

Water and Light Department
City of Columbia, Missouri

August 2013

Project No. 67546

prepared by

Burns & McDonnell Engineering Company, Inc.
Kansas City, Missouri

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LIST OF ABBREVIATIONS AND ACRONYMS

AC	Air Conditioner
ACH	Air Changes per Hour
AECI	Associated Electric Cooperative, Inc.
AHU	Air Handling Unit
Burns & McDonnell	Burns & McDonnell Engineering, Inc.
BOC	Building Operators Certification
BPU	Board of Public Utilities
CCGT	Combined Cycle Gas Turbine
CFB	Circulating Fluidized Bed
CFL	Compact Fluorescent Light/Bulb
CHP	Combined Heat and Power
COD	Commercial Operating Date
CSP	Concentrating Solar Power
CWL	City of Columbia, Missouri, Water and Light Department
DLC	Direct Load Control
DOE	Department of Energy (U.S.)
DSM	Demand Side Management
EIA	Energy Information Agency (Department of Energy)
EPA	Environmental Protection Agency (U.S. Government)
EPC	Engineer Procure Construct
EUI	Energy Use Intensity
FCTTC	First Contingency Total Transfer Capacity
GT	Gas Turbine
HRSG	Heat Recovery Steam Generator
HVAC	Heating, Ventilation, and Air Conditioning
IDC	Interest During Construction
IGCC	Integrated Gasification Combined Cycle
IRP	Integrated Resource Plan
KCP&L	Kansas City Power and Light Company
kW	Kilowatt
kWh	Kilowatt Hour
LEED	Leadership in Energy & Environmental Design (U.S. Green Building Council)
LGS	Large General Service
LMP	Locational Marginal Pricing
MEF	Modified Energy Factor

MISO	Midwest Independent Transmission System Operator, Inc.
MJMEUC	Missouri Joint Municipal Electric Utility Commission
MMBtu	Million British Thermal Units
MW	Megawatt
MWh	Megawatt Hour
NPV	Net Present Value
NREL	National Renewable Energy Laboratory
O&M	Operations and Maintenance
PC	Pulverized Coal
PPA	Power Purchase Agreement
PRB	Powder River Basin
PSEC	Prairie State Energy Campus
PV	Photovoltaic (solar collector)
RPS	Renewable Portfolio Standard
RTU	Roof Top Units
SCPC	Super Critical Pulverized Coal
SEER	Seasonal Energy Efficiency Ratio
SGS	Small General Service
TES	Thermal Energy Storage

EXECUTIVE SUMMARY

EXECUTIVE SUMMARY

Burns & McDonnell Engineering Company, Inc. (Burns & McDonnell) was retained by the City of Columbia, Missouri, Water and Light Department (CWL) to perform an update to the Integrated Resource Plan prepared by Burns & McDonnell in 2008 (2008 Study). This update to the 2008 Study (referred hereafter as the 2013 Update) evaluates the changes in the supply side resources to meet the future load requirements of Columbia, Missouri, since 2008 and provides analysis of future supply side resources to meet the expected needs of CWL. The existing DSM programs offered by CWL are reviewed in the context of the supply side futures. This report presents an overview of the analysis performed on the supply and demand side issues.

ES.1 LOAD FORECAST

The load forecast used in the analysis was based on a load forecast provided by CWL. The combined system energy requirements were projected to grow at an average annual rate of 1.8 percent during the time period in the 2008 Study. The revised forecast indicates that energy is projected to grow at 2.2 percent. The load factor is projected to increase from approximately 50 percent to approximately 52 percent over the study period. Demand was expected to grow at a slightly lower percentage (2.0 percent) than the annual energy growth. The combined base energy and demand requirements forecast for the CWL load are shown in Table ES-1. When compared to the forecast provided for the 2008 Study, both the energy and demand projections for the recent forecast are lower.

Table ES-1: CWL Demand and Energy Forecast

Year	Coincident Peak Demand (MW)		Total Energy (GWh)	
	2008 Study	2013 Update	2008 Study	2013 Update
2008	278		1,221	
2009	284		1,244	
2010	289		1,266	
2011	295		1,292	
2012	300		1,318	
2013	306	285	1,340	1,251
2014	311	289	1,362	1,278
2015	317	294	1,388	1,304
2016	322	300	1,414	1,329
2017	328	306	1,437	1,358
2018	333	312	1,459	1,393
2019	339	318	1,485	1,427
2020	344	325	1,511	1,461
2021	350	332	1,533	1,495
2022	357	338	1,564	1,532
2023	364	345	1,594	1,569
2024	371	353	1,629	1,607
2025	378	360	1,656	1,645
2026	385	366	1,686	1,663
2027	392	373	1,717	1,695
2028	399	381	1,752	1,727
Average Annual Increase	1.8%	2.0%	1.8%	2.2%

The forecast as provided by CWL includes projections of historical levels of demand side program acceptance by the CWL customers.

ES.2 EXISTING RESOURCES

CWL receives energy from a variety of existing generation resources, which includes jointly and wholly owned coal-fired steam units, natural gas-fired combustion turbines, wind, and landfill gas facilities. The most significant change in capacity since the 2008 Study has been the acquisition of the balance of the Columbia Energy Center (CEC). The CEC is now totally owned and operated by CWL. Table ES-2 lists the existing generation resources and their capacities available to CWL. A description of each of the existing CWL resources is provided in the Section 2.

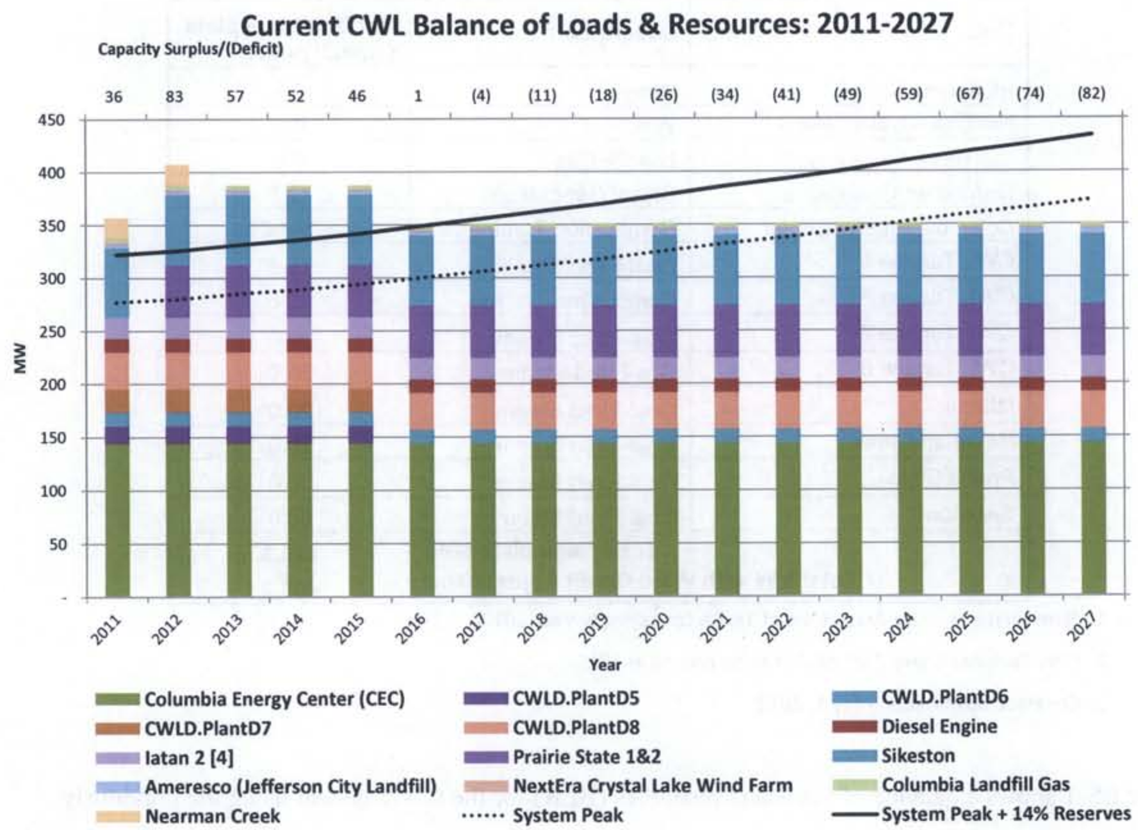
Table ES-2: Existing CWL Generation Resources

Unit	Description	Net Unit Nameplate Capacity (MW)
Bluegrass Ridge[1]	Wind	6.3
NextEra Crystal Lake 3 [1]	Wind	10.5
Columbia & Ameresco	Landfill Gas	5.0
Distributed Generators	Diesel Generation	12.5
Columbia Energy Center	Combustion Turbine	144.0
CWL Turbine 5[2]	Coal-Fired Steam	16.5
CWL Turbine 6	Combustion Turbine	12.5
CWL Turbine 7[2]	Coal-Fired Steam	22.0
CWL Turbine 8	Gas-Fired Steam	35.0
Iatan II	Coal-Fired Steam	20.0
Nearman Creek(3)	Coal-Fired Steam	20.0
Prairie State	Coal-Fired Steam	50.0
Sikeston	Coal-Fired Steam	66.0
Total Nameplate MW:		**420.3**
Total MW with Wind Credit Adjustment:		**408.2**

1. Nameplate capacity-Accredited at 14.7% for calendar year 2012.
2. CWL Turbines 5 and 7 scheduled to be retired in 2015.
3. Contract Termination May 1, 2013

Figure ES-1 shows a balance of loads and resources (BLR) for the CWL system using the previously described load forecast and existing generation and purchase resources assuming 14.7 percent accredited capacity of nameplate wind. A utility is also required to maintain reserves to meet unit outages and planning uncertainties. Prudent utilities also use reserves to meet economic growth larger than expected.

Figure ES-1: Current CWL Balance of Loads and Resources, 2011-2027



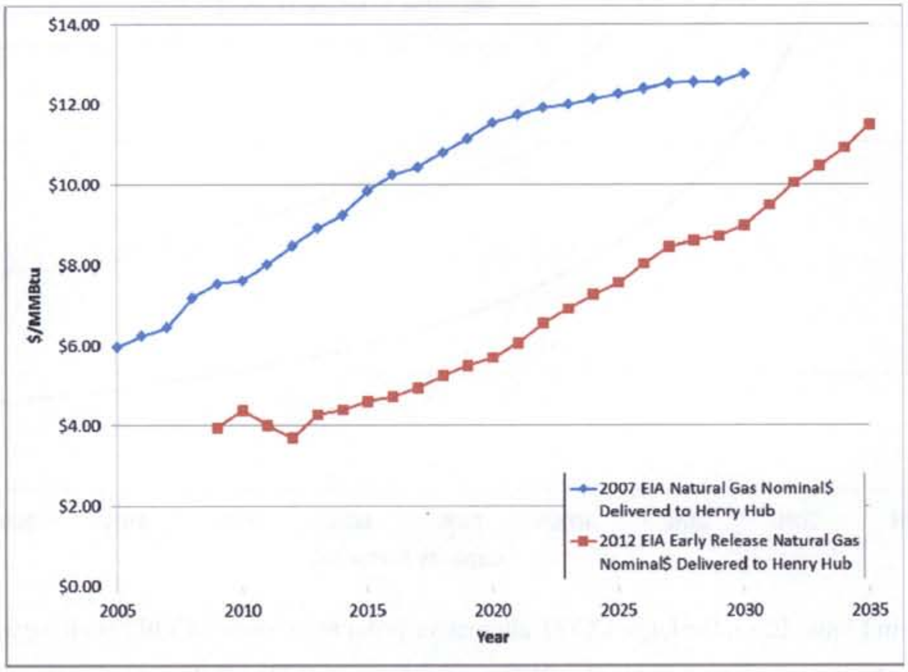
The major changes since the 2008 Study are the acquisition of the balance of the capacity at the CEC, the commercial operation of the Iatan II and Prairie State resources and the termination of the Nearman Creek Contract. It is assumed in the above figure that CWL Downtown Turbines 5 and 7 are retired at the end of 2015.

Specific to the CWL system, it is expected that CWL will require the addition of renewable energy to remain compliant with the City's renewable mandate. It is estimated that approximately an additional 55MW of wind generation will be required by 2030. This capacity could be reduced should the energy come from another qualifying renewable source.

ES.3 NATURAL GAS

The assumption for the cost of natural gas has been one of the most dramatic changes in resource plans developed since 2008. The rapid rise of hydraulic fracturing (fracking) in the drilling process for oil and natural gas in the United States has led to dramatic changes in the amount of natural gas available in the US. This supply glut has created pricing of natural gas well below the projections provided by various sources in the 2008 period. Figure ES-2 provides a comparison of the forecast for natural gas used in the 2008 Study and forecast data used in this 2013 Update. Both of the forecasts were developed using data from the Energy Information Agency.

Figure ES-2: EIA Natural Gas Forecast



ES.4 RESOURCE OPTIONS

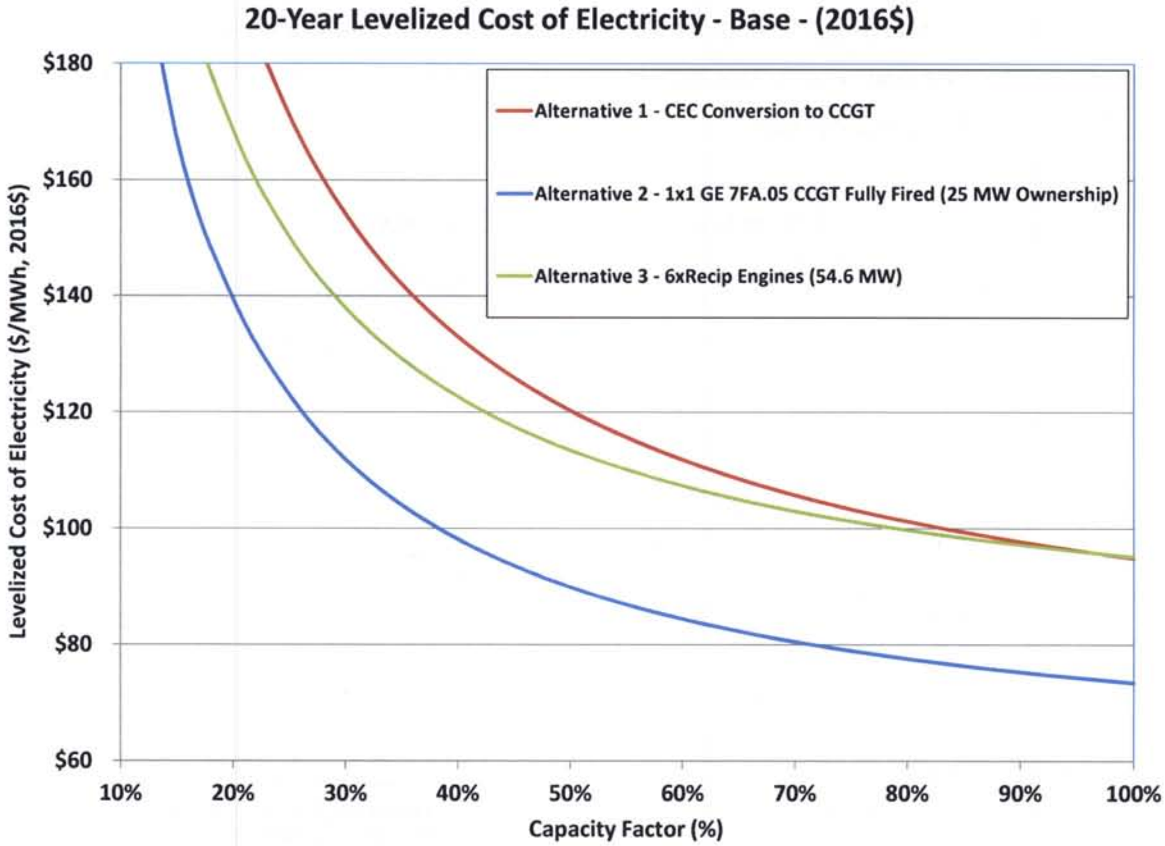
ES.4.1Traditional

The traditional resource options for CWL are all natural gas-fired resources. The options include:

- Partnership in a large combined cycle unit
- Locally constructed reciprocating engines or combustion turbines
- Addition of combined cycle operation to the CEC

Analysis of these assets is discussed in Section 3. The levelized cost of electricity (LCOE) of the assets across a range of capacity factors is shown in Figure ES-3

Figure ES-3: Levelized Cost of Electricity Evaluation



As presented in Figure ES-3, the large CCGT alternative provides a lower LCOE for all capacity factors between 10 to 100 percent compared to the CEC conversion to CCGT and the reciprocating engines based on the assumptions used herein. The large CCGT alternative is estimated to be lower cost due to its lower heat rate and lower capital cost investment due to the large economies of scale. However, CWL would not be able to develop and construct a large CCGT option solely on its own and would be dependent on participation from other utilities. The CEC conversion to CCGT operation is slightly higher in cost than the reciprocating engine alternatives across the varying capacity factors.

The results of the Strategist analysis using the base assumptions are shown in Table ES-3. Each of the two futures included hundreds of portfolio combinations. The associated 2013$ NPV of the lowest cost portfolio for each scenario is also included in Table ES-3.

Table ES-3: Strategist Scenarios Analyzed Base Assumptions

Scenario	Partner Future	CWL Control Future
	1	2
Plan Year	RESOURCE (Capacity)	RESOURCE (Capacity)
2013		
2014		
2015		
2016		
2017	DEF(6)	DEF(6)
2018	DEF(13)	DEF(13)
2019	DEF(20)	RECIP BLOCK(9) RECIP ENGINE(9) DEF(2)
2020	DEF(28)	RECIP ENGINE(9) DEF(1)
2021	DEF(36)	RECIP ENGINE(9)
2022	1x1 7FA CCGT 25%(95)	DEF(7)
2023		RECIP ENGINE(9) DEF(6)
2024		DEF(15)
2025		DEF(23)
2026		DEF(30)
2027		DEF(39)
2028		DEF(48)
2029	DEF(5)	DEF(55)
2030	DEF(13)	DEF(63)
NPV UTILITY COST (@ 4.0%) PLANNING PERIOD ($000)	$1,604,241	$1,626,830
% DIFFERENCE (FROM LOWEST COST)	*0.00%*	*1.41%*

Note: DEF(MW) indicates capacity purchases from the MISO market to cover the capacity deficit for that year.

ES.4.2 Solar PV Assessment

The value of solar energy to the CWL system is to reduce the amount of energy that needs to be imported from the MISO market and the transmission losses associated with the delivery. The losses include those on the CWL distribution system. Burns & McDonnell developed an analysis of the expected value of solar energy to CWL for use in assessing the appropriate level of rebate for its solar programs. The analysis compared the hourly output from the solar PV array provided by CWL to the corresponding day ahead LMP at the CWL MISO load node. Table ES-4 provides the NPV of the value of solar energy to CWL based on the LMP projections.

Table ES-4: Avoided Costs to CWL of 1kW Solar Array (20 years)

Annual Discount Rate	4%
Monthly Discount Rate	0.33%
NPV ($/kW)October 2013 through October 2033	$1,073.12
kWh/Year	1462.51

As the price of solar decreases (and electricity rates increase at the retail level) the use of solar will increase in net metering applications. Utilities will need to be aware of the potential erosion of retail kWh sales and the impact this may have on the rates. For example, at the residential level rates usually include a customer charge and an average kWh charge. If the kWh rate includes fixed costs of the utility, the decline in retail sales due to the net metered solar will reduce the revenue collected to cover the fixed costs. This will require the utility to either adjust the customer charge or increase its average kWh charge.

ES.5 DEMAND SIDE MANAGEMENT

Previous analyses for CWL with regard to Demand Side Management (DSM) programs have used "typical" data from other utilities. This data has been used where it was appropriate to reflect the expected results of potential DSM programs as developed by CWL. The scope of study for this 2013 Update was developed to move away from using data from outside sources and move towards the use of CWL specific data. Many of the most beneficial programs identified in the 2008 Study have been implemented by CWL. Several of these programs have been active since 2009. Certain aspects of the programs have been active for much longer. The actual results of the programs are used where possible.

The total demand and energy savings by program for the programs currently offered by CWL is shown below in Table ES-5. The table also provides the cost benefit of the programs. The benefits of the programs were valued using the net present value of the avoided demand and energy across the ten year period of 2012 to 2021 using the cost of demand and energy as determined in the supply side analysis discussed in Section 3. As seen, the benefits of the active programs are greater than the costs for all programs except for the Commercial HVAC program. The details of the analysis are included in Appendix C.

Table ES-5 Historical DSM Program Demand and Energy Savings

	Historial Participation and Demand/Energy Savings					Strategist Data				
	Historical Participation	Historical Participation Percentage	Total MW Reduction	Total MWh Reduction	Total Cost	$/MW $383,173.34	$/MWh $494.12			
RESIDENTIAL						Avoided Demand Cost ($)	Avoided Energy Cost ($)	Total Avoided Cost ($)	Continue Program	Program Savings
Home Performance with Energy Star										
2010	607	2.57%	0.173	570	$233,473	$66,289	$281,845	$348,134	yes	$114,661
2011	906	3.84%	0.245	843	$515,369	$93,877	$416,334	$510,211	no	($5,158)
Total	1,513	6.40%	0.418	1,413	$748,842	$160,166	$698,178	$858,345	yes	$109,503
Air Conditioner or Heat Pump Rebates										
2010	192	0.81%	0.112	289	$65,500	$42,915	$142,701	$185,617	yes	$120,117
2011	368	1.56%	0.133	564	$141,230	$50,962	$278,572	$329,534	yes	$188,304
Total	560	2.37%	0.245	853	$206,730	$93,877	$421,273	$515,150	yes	$308,420
Online Energy Audit										
2010	1,396	5.91%	0.000	377	$0	$0	$186,243	$186,243	yes	$186,243
2011	605	2.56%	0.000	163	$8,260	$0	$80,714	$80,714	yes	$72,454
Total	2,001	8.47%	0.000	540	$8,260	$0	$266,957	$266,957	yes	$258,697
Energy Audits										
2010	276	1.17%	0.000	317	$0	$0	$156,418	$156,418	yes	$156,418
2011	576	2.44%	0.000	105	$0	$0	$52,006	$52,006	yes	$52,006
Total	852	3.61%	0.000	422	$0	$0	$208,424	$208,424	yes	$208,424
Tree Power and Landscape Audit										
2010	98	0.41%	0.005	33	$7,840	$1,839	$16,477	$18,316	yes	$10,476
2011	98	0.41%	0.002	102	$7,400	$575	$50,442	$51,017	yes	$43,617
Total	196	0.83%	0.006	135	$15,240	$2,414	$66,919	$69,333	yes	$54,093
Window Air Conditioner Exchange Program										
2010	125	0.53%	0.063	91	$22,950	$23,948	$45,088	$69,037	yes	$46,087
2011	30	0.13%	0.000	22	$0	$0	$10,821	$10,821	yes	$10,821
Total	155	0.66%	0.063	113	$22,950	$23,948	$55,909	$79,858	yes	$56,908
Total Residential Prog	-84 2,583	-0.36% 10.93%	0.732	3,476	$1,002,022	$280,406	$1,717,660	$1,998,066	yes	
COMMERCIAL										
Lighting Incentive Program										
2010	11	0.17%	0.185	648	$23,809	$70,887	$320,188	$391,075	yes	$367,266
2011	50	0.79%	0.460	1,449	$127,407	$176,260	$715,923	$892,183	yes	$764,776
2012	68	1.08%	0.636	1,943	$161,181	$243,698	$960,036	$1,203,734	yes	$1,042,553
Total	129	2.04%	1.281	4,040	$312,397	$490,845	$1,996,147	$2,486,992	yes	$2,174,595
HVAC										
2012	13	0.21%	0.058	100	$282,350	$22,224	$49,643	$71,867	no	($210,483)
Total	13	0.21%	0.058	100	$282,350	$22,224	$49,643	$71,867	no	($210,483)
Total Commercial Programs			1.339	4,140	$594,747	$513,069	$2,045,789	$2,558,859	yes	$1,964,112
Total All Programs			2.071	7,617	$1,596,769	$793,475	$3,763,450	$4,556,925	yes	$2,960,156

[1] Contractor Incentives are not included in the table above. These costs are marketing costs creating market transformation.
The incentives will be diminished when the market for the service is mature and the data reporting is automatic.
Contractor incentives were $318,000 in FY2010 and $412,000 in FY2011.

Using the historical kW and kWh reductions for participants in the program and the participation rates, analysis was performed to project the expected demand and energy reductions based on the estimated housing and commercial accounts in CWL's service area. Table ES-6 and Table ES-7 provide the summary of the estimated reductions while Figure ES-4 and Figure ES-5 provide graphs of the expected impact to CWL's forecast.

Table ES-6 Projected Energy Savings by DSM Program

	2013 (MWh)	2014 (MWh)	2015 (MWh)	2016 (MWh)	2017 (MWh)	2018 (MWh)	2019 (MWh)	2020 (MWh)	2021 (MWh)	2022 (MWh)
Energy Savings										
Home Performace with Energy Star - R	496	992	1,488	1,983	2,479	2,975	3,471	3,967	4,463	4,959
Air Conditioner/Heat Pump Rebates - R	458	916	1,374	1,832	2,290	2,748	3,206	3,664	4,122	4,580
Online Energy Audit - R	198	396	594	792	990	1,188	1,386	1,584	1,782	1,980
Tree Power & Landscape Audit - R	66	132	199	265	331	397	464	530	596	662
Window Air Conditioner Exchange Program - R	63	126	189	251	314	377	440	503	566	629
Lighting Incentive Program - C	1,141	2,284	3,431	4,580	5,733	6,888	8,046	9,207	10,371	11,537
HVAC - C	292	585	878	1,172	1,467	1,763	2,059	2,356	2,654	2,953
Potential Energy Savings	2,714	5,431	8,152	10,877	13,605	16,337	19,072	21,811	24,554	27,300
Energy Savings from Current DSM Programs [1]	7,617	7,617	7,617	7,617	7,617	7,617	7,617	7,617	7,617	7,617
Total Potential Energy Savings	10,330	13,048	15,768	18,493	21,221	23,953	26,689	29,428	32,170	34,917

[1] Actual energy savings from FY 2010 and FY 2011.

Figure ES-4 Projected Energy Forecast Reduction by DSM Program

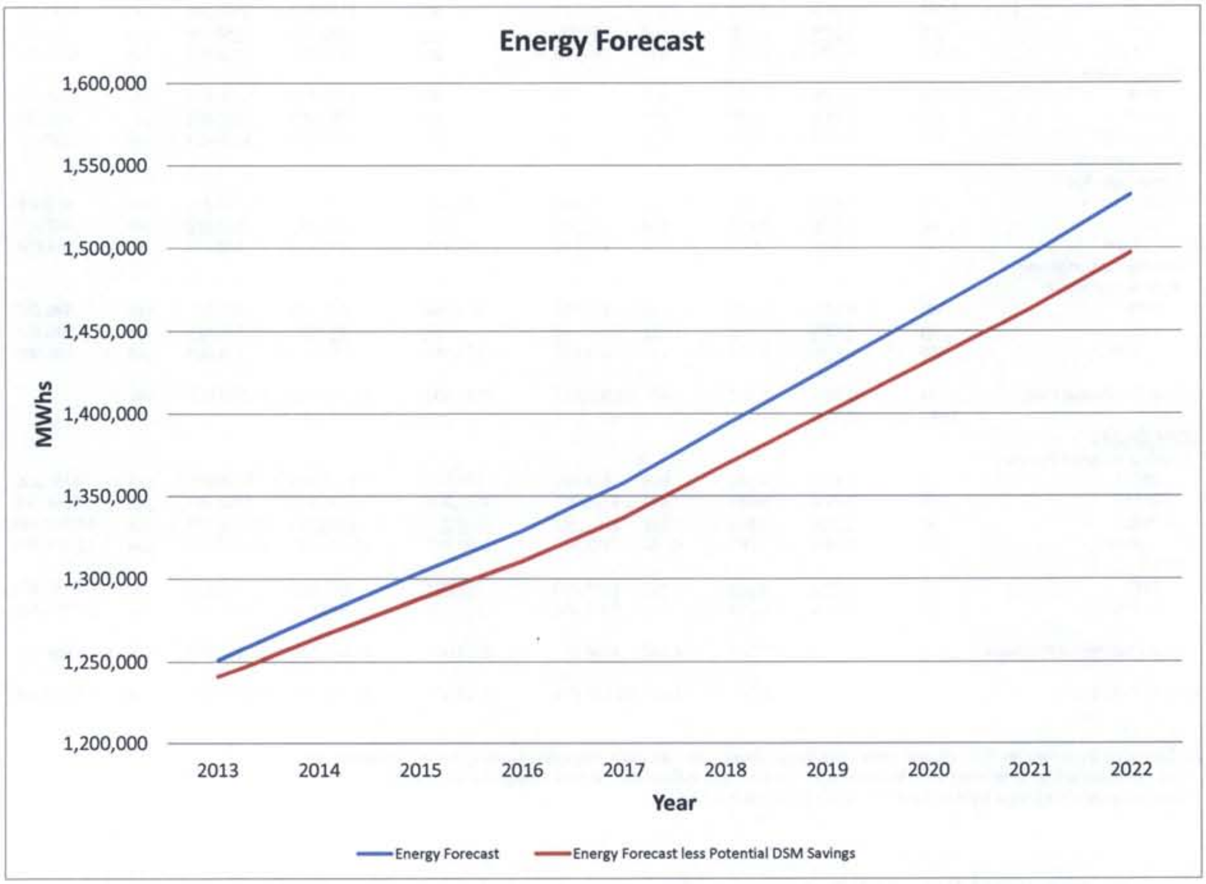
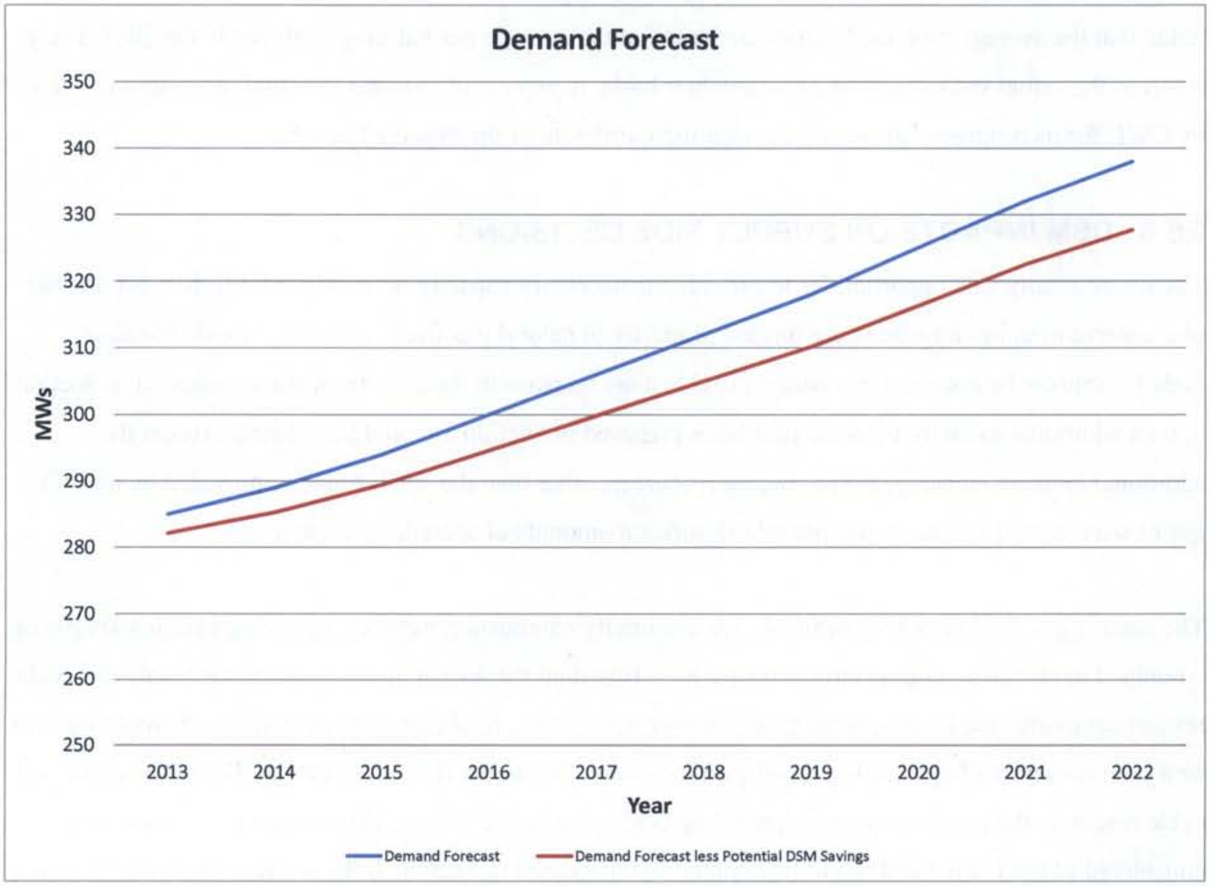


Table ES-7 Projected Demand Savings by DSM Program

	2013 (MW)	2014 (MW)	2015 (MW)	2016 (MW)	2017 (MW)	2018 (MW)	2019 (MW)	2020 (MW)	2021 (MW)	2022 (MW)
Demand Savings										
Home Performace with Energy Star - R	0.149	0.299	0.448	0.597	0.746	0.896	1.045	1.194	1.344	1.493
Air Conditioner/Heat Pump Rebates - R	0.133	0.265	0.398	0.530	0.663	0.796	0.928	1.061	1.193	1.326
Online Energy Audit - R	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Tree Power & Landscape Audit - R	0.003	0.007	0.010	0.013	0.017	0.020	0.023	0.026	0.030	0.033
Window Air Conditioner Exchange Program - R	0.034	0.069	0.103	0.138	0.172	0.207	0.241	0.276	0.310	0.344
Lighting Incentive Program - C	0.378	0.756	1.136	1.516	1.897	2.280	2.663	3.047	3.433	3.819
HVAC - C	0.123	0.247	0.371	0.496	0.620	0.745	0.870	0.996	1.122	1.248
Potential Demand Savings	0.821	1.643	2.466	3.290	4.116	4.943	5.771	6.601	7.431	8.263
Demand Savings from Current DSM Programs [1]	2.071	2.071	2.071	2.071	2.071	2.071	2.071	2.071	2.071	2.071
Total Potential Demand Savings	2.891	3.713	4.537	5.361	6.187	7.014	7.842	8.671	9.502	10.334

[1] Actual demand savings from FY 2010 and FY 2011.

Figure ES-5 Projected Demand Forecast Reduction by DSM Program



A comparison was made to the actual results for two of the programs versus those projected in the 2008 Study. The two programs selected allowed the actual versus projected values to be compared due to the specificity of the targeted appliance of the program. The comparisons are shown in Table ES-8.

Table ES-8 Comparison of Actual versus Estimated DSM Results for Selected Programs

		Average kW		Average MWh	
		2008 Study	Actual	2008 Study	Actual
Residential HVAC		0.95	0.44	0.67	1.522
Commercial Lighting		22.1	9.9	63.1	31.3

The results of the residential HVAC program indicate that the newer air conditioners are providing less of a peak reduction than estimated, but greater energy savings. For the Commercial Lighting program, the average demand and energy reductions are approximately half of the projected amounts. It should be noted that the average projected values are based on the average per building analyzed in the 2008 Study whereas the actual values may be on a customer basis. In any event, moving to actual reductions as seen by CWL for its programs allows a more definitive estimate of the expected benefits.

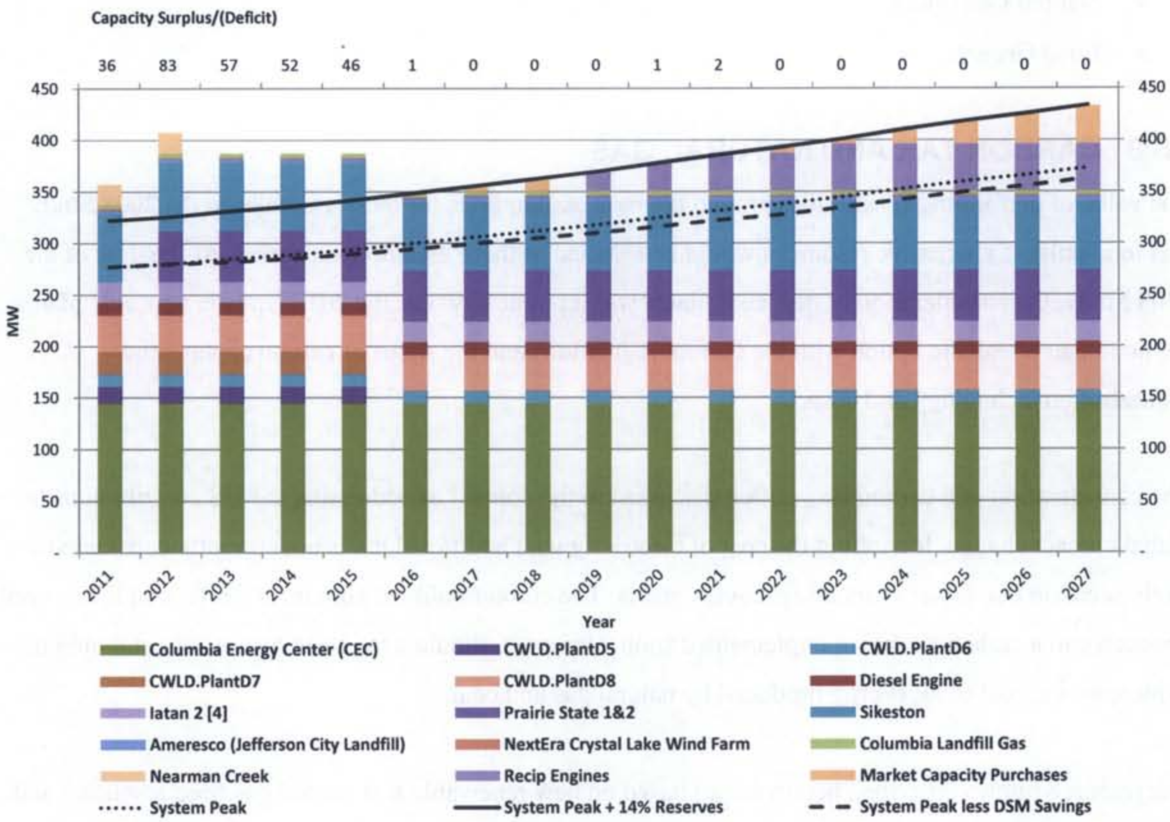
ES.6 DSM IMPACTS ON SUPPLY SIDE DECISIONS

The future supply side opportunities to provide the necessary capacity required for CWL to meet its load plus reserve margin obligations are limited primarily to natural gas-fired resources. Should biomass fueled resources be acquired that would provide a net increase in capacity from that considered in Section 3, then additional capacity from the portfolios prepared in Section 3 would be reduced. Absent the additional biomass capacity, the renewable resources, other than the small capacity provided by landfill gas or wind accreditation, do not provide significant amounts of accredited capacity.

The natural gas fired resources available are essentially combustion turbines, operating in either simple or combined cycle mode, and reciprocating engines. Based on the screening assessment, the combined cycle resource provided the lower overall costs. However, for CWL to obtain these economics, it would have to be a joint owner in a large facility developed by others. Due to the risk of the availability of the combined cycle resource, the portfolio with reciprocating engines, which CWL could construct on its own, were considered as the likely portfolio to be realized. As discussed in Section 3, the conversion of the CEC to a combined cycle operation may also be an attractive option to replace a certain amount of the reciprocating engines.

The adjusted forecast due to expected impacts of the DSM programs reviewed in Section 4 currently being managed by CWL is shown on Figure ES-6. The figure also shows the portfolio under the future where CWL installs reciprocating engines to meet its power supply requirements. The engines have a rating of 9MW and can be installed one at a time. The impact of the DSM programs is to provide an opportunity to delay installation of capacity as compared to what would have been required without the DSM programs. If CWL is able to obtain more demand reductions than indicated, the opportunity may be created to delay additional capacity.

Figure ES-6 BLR with Expected DSM Impacts and Reciprocating Engine Strategist Future



In addition to the capacity impacts, CWL will be experiencing a shift in the sources of energy over time. The amount of electrical energy provided by coal will decline over time, both in real quantities and percentage of total energy, as the incremental energy required by the market is provided by natural gas-fired facilities and renewable sources. The amount of renewable energy will grow based on the CWL Renewable Portfolio Standard. This shift will assist in CWL reducing its emissions of carbon due to electricity production.

ES.7 SENSITIVITIES

There are a variety of sensitivities that can be performed on the input assumptions for the selection of the above portfolios. The inclusion of adjustments to the following assumptions was provided in the 2008 Study:

- Carbon Tax
- Natural Gas prices
- Load Growth

ES.8 CARBON TAX AND NATURAL GAS

The value of performing sensitivities around the base assumptions for these variables in the 2008 Study was to identify if alternative resources would be selected as these assumptions varied. At the time of the 2008 Study, the consideration of new coal plants was a possibility. For the 2013 Update, new coal plants are no longer a realistic option with the current regulations and the status of carbon capture and sequestration technology and costs.

The consideration of a carbon tax is often discussed in the context of addressing the US contributions to global climate change. Increasing the cost of electricity with additional tax is not currently considered a likely scenario due to the economic recovery status. The current political climate at the federal level is not conducive to a carbon tax being implemented soon. However, should a tax be levied, its effect would be to increase the cost of all energy produced by natural gas and coal.

The resource futures described herein are all based on new renewable and natural gas fired resources and continuing the DSM programs. Therefore, the impact of a carbon tax would not change the resource futures available to CWL, but would make the cost of all of the futures more expensive. A carbon tax would further the installation of wind and solar renewable energy by making the cost of that energy more attractive. CWL is also pursuing renewable energy from these sources and could increase its acquisition should a carbon tax be implemented.

With regard to natural gas, the forecast of natural gas used in this 2013 Update is based on an adjusted EIA forecast of natural gas. It is expected that there will be two issues that could potentially lead to a more rapid increase in the price of natural gas.

The first of these issues is the debate over whether to allow export of natural gas from the US. It is expected that if exports of liquefied natural gas are allowed, the price of domestic natural gas will increase towards its value on the world market. This could result in a two to three times increase in the price of natural gas.

The second potential impact could arise from the pressure from environmental regulations enacted to reduce the emissions of methane from the gas fields and the hydrological fracturing process. The costs of these regulations would be reflected in the price of the gas. Table ES-9 provides the results of increasing the natural gas forecast by 50 percent from the base forecast.

Table ES-9 NPV of Resource Futures with Gas Sensitivity
($000s)

	Partner	CWL Control	Diff
Base	$ 1,604,241	$ 1,626,830	$ 22,589
Gas Sensitivity	$ 1,687,432	$ 1,703,830	$ 16,398

When reviewing the options available to CWL, the inclusion of a carbon tax or higher forecast of natural gas prices would not change the selection of alternatives, since they are based on what CWL could potentially obtain to meet its capacity obligations due to its increasing load. The net effect would be to increase the overall cost of the futures, not change the selection.

ES.9 LOAD FORECAST ADJUSTMENTS

The importance to reviewing the impact of looking at load on the forecast is to determine if it would have a material change in the supply side portfolio using the base forecast. Due to the ongoing efforts by CWL with DSM and the slow economic growth, it is not expected that a significant increase would occur in CWL's load forecast. If it did, it would simply advance the time when new resources would be needed and the amount. It would not change the technology selected.

If the load forecast decreased, then it would delay the time when resources are needed and potentially the amount. The load forecast has already declined from the base forecast used in the 2008 Study. Future decreases due to further efforts in the CWL DSM programs are projected above. As CWL works through its housing stock and customers move to more efficient appliances influenced by federal efficiency standards, the benefits from DSM will diminish.

The largest impact to load forecast could conceivably come from the ubiquitous appearance of solar PV at the net metered level. As discussed in Section 3, solar PV could reach retail parity within the next few years. Should a carbon tax be implemented or the price of natural gas suddenly increase, parity would be potentially be achieved more quickly and with a larger margin in favor of solar. The resulting impact on the CWL demand and energy requirements could be substantial as customers begin rapid acceptance of solar PV on a net metered basis. The solar market already includes 275 watt plug in solar PV packages that can be purchased, taken home and plugged into an outdoor outlet. It is expected that many homes would opt for larger installations.

CWL purchases essentially all of its energy from the MISO market. It sells energy from its generating resources into the MISO market. The revenues from the energy sales are used to offset the cost of the energy purchases. The increased use of net metered solar will reduce the amount of energy required to be purchased from the MISO market. As discussed in Section 3, natural gas-fired resources will be required to work with the wind and solar energy as the load curve becomes more variable. This will impact the revenues from the generation resources sold in to the MISO market. It is too early to begin predicting the dollar ramifications of the impacts of solar, but the potential trend is to reduce the load costs and change the revenues obtained from CWL generation resources.

ES.10 CONCLUSIONS

Based on the analysis performed herein, Burns & McDonnell has developed the following conclusions.

1. CWL's base load forecast used in this 2013 Update is lower than the base forecast provided in the 2008 Study. The forecast includes the historical impacts of CWL DSM efforts.

2. Based on a review of CWL existing DSM programs and CWL's more attractive supply side expansion options, CWL should continue to pursue the existing DSM programs that it manages. The Commercial HVAC program should be reviewed to determine if its benefit can be increased.

3. CWL should continue to work with the City to improve the application and enforcement of more efficient building codes across the commercial and residential sectors. The current situation where CWL attempts to entice building owners to improve their building's efficiency through use of CWL incentives after they are constructed is not a good use of CWL capital or human resources.

4. Due to the number of existing and to be implemented federal efficiency standards and the rising cost of electricity, expansion into new DSM programs does not appear to be warranted. There are focused, short term programs that may be of use, such as second refrigerator turn-ins and targeted industrial offers that could have benefit. However, CWL DSM programs currently offer incentives in the higher value DSM areas.

5. CWL's supply side expansion options are essentially limited to natural gas fired and renewable energy resources. The need to add these resources, with the expected load forecasts, does not occur until approximately 2019. CWL should monitor the cost of capacity from the area market to determine if the actual construction of resources is more economical.

6. Should CWL determine that the CWL Controlled resource future is the course it desires to take, a detailed engineering analysis of the costs to expand the CEC to a combined cycle operation should be developed. Investigation into necessary permit modifications should also be made. This detailed evaluation should be compared to the value of the output of the facility to the MISO market and how it compares to the cost of the reciprocating engines.

7. The potential impact to the electric utility industry of solar PV achieving retail parity is significant. The timing of achieving this parity level could be within the next few years depending on the pricing of natural gas and general rate increases coming about due to the rising real cost of electricity. For CWL, a significant expansion of net metered solar PV would have a large impact on its MISO energy purchases, its sales from its generation and the capacity necessary to meet its load plus reserve obligations.

8. CWL should continue to review its rate structure to review the impact of declining sales from DSM and the potential impact due to increasing use of net metered solar PV.

9. An increase in the cost of wholesale electricity through a carbon tax or natural gas prices increasing will expand the value of DSM and net metered solar PV to CWL customers. It will not materially change the make-up of the lower cost supply side portfolio identified herein. If, however, CWL's load is materially affected by the large acceptance of net metered solar PV, then the lower cost portfolio would also change. It is expected that the need for additional natural gas fired resources would decline and be delayed.

* * * * *

SECTION 1.0
INTRODUCTION

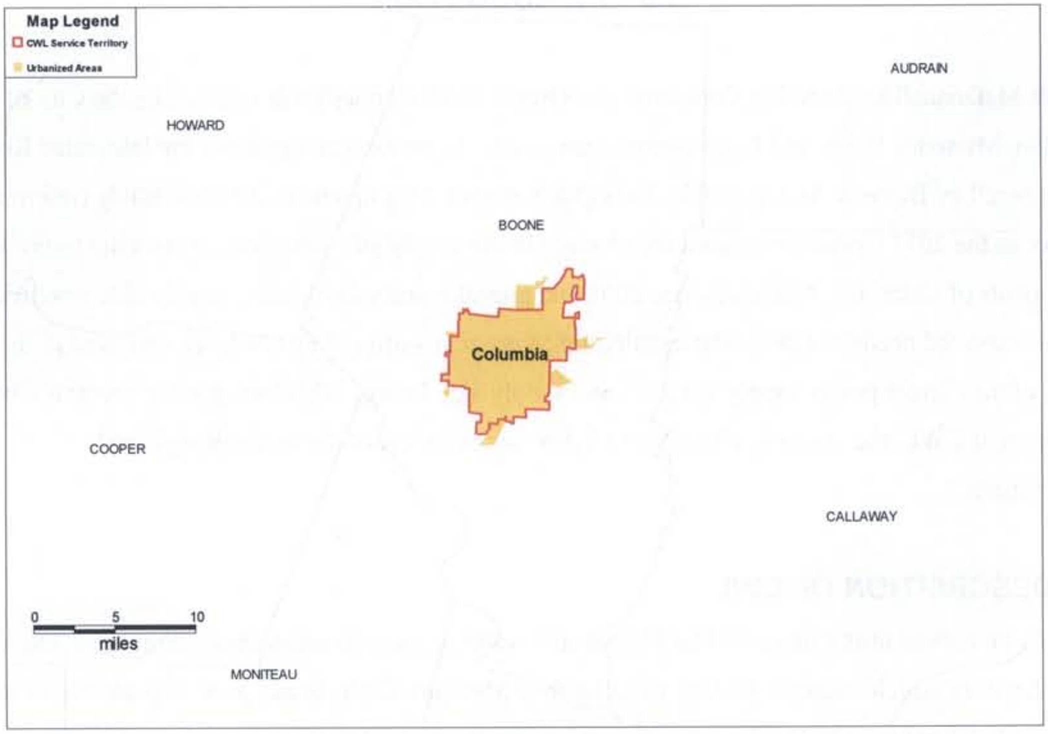
1.0 INTRODUCTION

Burns & McDonnell Engineering Company, Inc. (Burns & McDonnell) was retained by the City of Columbia, Missouri, Water and Light Department (CWL) to perform an update to the Integrated Resource Plan prepared by Burns & McDonnell in 2008 (2008 Study). This update to the 2008 Study (referred hereafter as the 2013 Update) evaluates the changes in the supply side resources to meet the future load requirements of Columbia, Missouri since 2008 and provides analysis of future supply side resources to meet the expected needs of CWL. The existing DSM programs offered by CWL are reviewed in the context of the current power supply situation and supply side futures. This introduction presents a brief description of CWL, the purpose of the 2013 Update, an overview of the methodology, and considerations.

1.1 DESCRIPTION OF CWL

CWL is a municipal utility that provides electric and water services to customers within the within the service territory which includes the City of Columbia, Missouri. CWL began providing service to the residents of Columbia in 1904. The approximate service territory of CWL is indicated on Figure 1-1. As of December 2012, CWL served approximately 46,600 residential, commercial, and large commercial/industrial electric customers.

Figure 1-1: Approximate CWL Service Territory



During FY2012, CWL customers had a demand peak of 272MW and consumed approximately 1,175 GWh of electricity. The energy consumed in 2012 was slightly less than in 2011, in which the peak was approximately 5MW more. CWL obtains the majority of its energy from shares of traditional supply side resources powered by coal and gas, power purchase agreements, and market spot energy. Increasing amounts of renewable energy are also being acquired. Section 2 discusses the existing resources available to CWL in meeting its supply obligations.

1.1.1 Renewable Portfolio Standard

The citizens of Columbia voted on November 4, 2004 to implement a Renewable Portfolio Standard (RPS) for CWL. The RPS requires CWL to obtain a portion of its power supply from qualified renewable resources. The RPS includes the following requirements:

(a) *The city shall generate or purchase electricity generated from eligible renewable energy sources at the following levels:*

  (1) *Two (2) percent of electric retail sales (kWhs) by December 31, 2007;*

  (2) *Five (5) percent of electric retail sales (kWhs) by December 31, 2012;*

  (3) *Ten (10) percent of electric retail sales (kWhs) by December 31, 2017; and*

(4) Fifteen (15) percent of electric retail sales (kWhs) by December 31, 2022.

(b) This renewable energy shall be added up to these kilowatt hour levels only to the extent that it is possible without increasing electric rates more than three (3) percent higher than the electric rates that would otherwise be attributable to the cost of continuing to generate or purchase electricity generated from one hundred (100) percent non-renewable sources (including coal, natural gas, nuclear energy and other nonrenewable sources).

(c) Eligible renewable energy generation may be provided by wind power, solar energy, bio-energy sources or other renewable sources which meet the environmental criteria approved by the city council after review by the environment and energy commission and the water and light advisory board. Electricity purchased from on-site renewable energy systems owned by Columbia Water and Light customers ("net metering") may be included within the calculation of the levels required in subsection (a).

(d) Renewable energy generation sources located within Missouri may receive preferential consideration in the selection process.

CWL currently is acquiring energy from wind and landfill projects. It is actively developing solar projects with its customers and other landfill projects in the area. Based on projections, CWL is ahead of the RPS energy requirements.

1.1.2 Demand Side Management

CWL also operates an active demand side management (DSM) service for its customers. A variety of programs are offered to its residential, commercial and industrial customers. These programs include, but are not limited to, education, active load control and load shedding, appliance and lighting rebates and loan programs, energy audits, and tree planting.

1.1.3 Transmission Interconnections

The majority of CWL energy is provided to its load via transmission lines from supply sources external to the City. These lines are owned and operated by AmerenUE (Union Electric) and Associated Electric (AECI). CWL interconnects with AECI at 161kV at the Boone and Bolstad substations. A single interconnect with AmerenUE exists at 161kV at the Perche substation. Future planned system improvements include new ties to the 161kV system at McBaine, Grindstone, Perche and the Municipal Power Plant.

CWL operates within the Midwest ISO as a market participant. This provides CWL access to network transmission service within the Midwest ISO and allows the purchase and sale of energy into the Midwest

ISO at the nodal locational marginal price established at CWL load and generation nodes, respectively. Recently, MISO has initiated an annual capacity auction. CWL also maintains a control area that requires CWL to meet certain energy balancing requirements for its generation and load. CWL acquires energy for its load from the Midwest ISO market at the CWLD.CWLD node. AECI does not operate within the Midwest ISO market, while Ameren does. Therefore, CWL is on the border of the Midwest ISO market.

1.2 PURPOSE OF STUDY

CWL periodically analyzes its projection of load to be served as compared to its sources available to satisfy its load obligations. The 2013 Update was commissioned to provide an update to the 2008 Integrated Resource Plan (2008 Study) that provided direction for supply side and demand side (DSM) resource development. The consideration of DSM potential was to use data specific to CWL's customer base, programs that have been offered and new programs based on the recommendations of the 2008 Study. The overall objective of the analysis was to review the changes since the 2008 Study and make any necessary revisions to the more attractive supply and demand side options in meeting CWL forecasted demand and energy requirements recommended in the 2008 Study.

1.3 STUDY APPROACH

The first step in the approach to the update was to review the information available from CWL. This data included the load forecast, changes in its supply side resources, RPS requirements, existing demand side programs, etc. The load projections were then combined with the available resources to determine if and when the existing resources would be inadequate to meet the load projections. A review of both the capacity (MW) capabilities and the energy (MWh) sources to meet projections was considered.

Assumptions on a variety of inputs to the analysis were developed and provided for review by CWL. This included fuel and market energy price forecasts, operation and maintenance costs for existing resources, financial parameters, demand side impacts from a variety of programs, etc. Burns & McDonnell developed supply side resource options for consideration and reviewed the projected capital, operations and maintenance costs with CWL. The DSM programs offered by CWL include those that were recommended from the 2008 Study. No new programs were considered to be added in the 2013 Update. Review of expected results and benefits were developed based on CWL specific information.

An analysis of potential supply side resources to meet the load projections was performed. This analysis was done to establish the attractive future considering the load forecast being met with supply side resources while meeting the RPS requirements. Expected results from the current offered DSM programs were developed and considered in the review of supply side needs.

The traditional supply side future was then integrated with the attractive demand side options to provide an integrated demand and supply side analysis.

1.4 ANALYSIS METHODOLOGY

Burns & McDonnell prepared the assumptions required for modeling the power supply futures considered for CWL. The resource expansion planning model, Strategist, was used to analyze the supply and demand side options in order to arrive at the more attractive alternatives for consideration by CWL. Strategist is a probabilistic resource expansion planning software package. The measurement of "best" is based on lowest net present value (NPV) of the costs of the futures. The analysis covered the period 2013 to 2030.

1.4.1 Supply Side

Supply side options were selected for consideration by Burns & McDonnell based on its experience with current available options. CWL system capacity requirements were considered with allowance of a reserve margin of 14 percent of peak load less firm purchases. The resource options were developed considering the expected deficits of capacity for CWL and typical sizing for the options.

For supply side options, Strategist is used to select the MW amount and timing of resource options to add and satisfy the utility's annual requirements over the study period. The program iterates to arrive at optimal portfolios for the options considered. The analysis included existing and potential environmental restrictions being discussed on power plant emissions.

1.4.2 Demand Side

The existing DSM programs being offered by CWL were reviewed. The load forecast provided by CWL included the effects of ongoing DSM programs which were considered to continue at their historic levels. The 2013 Update did not consider any new programs but directed efforts to identify more CWL specific information on participation levels, actual demand and energy reductions achieved and expected reductions of demand and energy based on estimates of CWL end use inventory.

1.5 STUDY CONSIDERATIONS

In the development of any power supply study, there are a variety of uncertainties that confront the utility and its customers. The major issues confronting utilities today on supply side options are the rapidly escalating costs of resource options, fuel availability and cost, dealing with the aspects of carbon legislation and the advances in technology. For the demand side, the major uncertainty is reliance on consumers accepting the programs offered, achieving the estimated reductions, and retaining the reductions once implemented. Therefore, a consideration in the 2013 Update was the ability for CWL to react to changing conditions and still meet its load-serving obligations in a cost effective, reliable manner.

In the preparation of this report, the information provided by CWL was used by Burns & McDonnell to make certain assumptions with respect to conditions which may exist in the future. While Burns & McDonnell believes the assumptions made are reasonable for the purposes of this report, it makes no representation that the conditions assumed will, in fact, occur. In addition, while Burns & McDonnell has no reason to believe that the information provided by CWL, and on which it has relied, is inaccurate in any material respect, Burns & McDonnell has not independently verified such information and cannot guarantee its accuracy or completeness. To the extent that actual future conditions differ from those assumed herein or from the information provided to Burns & McDonnell, the actual results will vary from those forecasted.

In addition, estimates and projections prepared by Burns & McDonnell relating to construction costs and schedules, operation and maintenance costs, equipment characteristics and performance, and operating results are based on Burns & McDonnell's experience, qualifications and judgment as a professional consultant. The estimates and projections contained herein prepared by Burns & McDonnell reflect screening level assumptions about the facilities and fuels represented. While the estimates are considered suitable for use in production cost modeling analyses to select preferable resource options to pursue, Burns & McDonnell has no control over economic conditions, specific site issues, competitive bidding or market conditions and other factors affecting actual costs should any of the facilities included herein be pursued. Therefore, Burns & McDonnell does not guarantee that actual costs, performance, schedules, and operations will not vary from the estimates and projections prepared for purposes of this planning study by Burns & McDonnell.

1.5.1 Allowance for Flexible Future

Flexibility for a utility, for purposes of the 2013 Update, is considered the ability of the utility to avoid becoming so invested in its resources that it cannot manage its costs due to increasing or decreasing load, new technologies, or anticipated regulations. An important aspect of flexibility for a utility requires that the investment made in an asset is such that the asset is not obsolete prior to recovery of the investment.

1.5.2 Energy Standards

The Energy Act of 2007 (Act) was enacted on December 19, 2007. The Act includes requirements for efficiency enhancements to appliances, lighting and other end-use devices. One of the more interesting aspects of the Act is the significant increase in efficiencies required for incandescent lighting. The anticipated effect of this legislation is to reduce energy consumption. New incandescent lighting standards took affect that reduce the ability to use the traditional incandescent bulbs. Instead, compact fluorescent bulbs will become the new normal for most residential lighting. Also, new residential air conditioning standards have taken affect that require a minimum SEER rating of 13 for the CWL area. These standards reduce the ability of the utility to achieve energy efficiency reductions due to the natural migration of appliances to the higher efficiency standards.

For purposes of this analysis, the assumption considered by Burns & McDonnell is that the impacts of certain DSM programs will impact the load growth until full market saturation is achieved. Once the saturation is achieved, the load will then grow at the current projected rate forecasted by CWL.

1.5.3 Carbon Legislation

Since the 2008 Study, the interest in enacting legislation aimed towards reducing greenhouse gases has decreased. The decrease is primarily associated with concern over the impact that increasing costs of energy with a carbon tax might have on the economic recovery from the 2008 recession. Recently, the state of California has initiated a greenhouse gas cap and trade auction. Results of the first auction indicate that the median price received ranged from approximately $11 to $13 per metric ton. The 2013 Update included consideration of carbon tax and its impact on anticipated resource plans.

* * * * *

SECTION 2.0

EXISTING CONDITIONS

2.0 EXISTING CONDITIONS

The service territory for CWL primarily serves municipal load within the city limits of Columbia, Missouri. The utility has a mixture of traditional and renewable supply side resources to meet these load requirements. These resources include self-owned generation as well as power purchase contracts. In addition to the supply side resources, CWL has numerous demand side load management and conservation programs that it offers its customers to reduce demand and energy consumption. This section of the report describes the load projection and the existing supply and demand side resources CWL has available.

2.1 LOAD FORECAST

The load forecast used in the analysis was based on a load forecast provided by CWL. The combined system energy requirements were projected to grow at an average annual rate of 1.8 percent during the time period in the 2008 Study. The revised forecast indicates that energy is projected to grow at 2.2 percent. The load factor is projected to increase from approximately 50 percent to approximately 52 percent over the study period. Demand was expected to grow at a slightly lower percentage (2.0 percent) than the annual energy growth. The combined base energy and demand requirements forecast for the CWL load are shown in Table 2-1. When compared to the forecast provided for the 2008 Study, both the energy and demand projections for the recent forecast are lower.

Table 2-1: CWL Demand and Energy Forecast

Year	Coincident Peak Demand (MW)		Total Energy (GWh)	
	2008 Study	2013 Update	2008 Study	2013 Update
2008	278		1,221	
2009	284		1,244	
2010	289		1,266	
2011	295		1,292	
2012	300		1,318	
2013	306	285	1,340	1,251
2014	311	289	1,362	1,278
2015	317	294	1,388	1,304
2016	322	300	1,414	1,329
2017	328	306	1,437	1,358
2018	333	312	1,459	1,393
2019	339	318	1,485	1,427
2020	344	325	1,511	1,461
2021	350	332	1,533	1,495
2022	357	338	1,564	1,532
2023	364	345	1,594	1,569
2024	371	353	1,629	1,607
2025	378	360	1,656	1,645
2026	385	366	1,686	1,663
2027	392	373	1,717	1,695
2028	399	381	1,752	1,727
Average Annual Increase	1.8%	2.0%	1.8%	2.2%

The forecast as provided by CWL includes projections of historical levels of demand side program acceptance by the CWL customers.

2.2 CURRENT DSM PROGRAMS

The 2008 Study made several recommendations about DSM programs which were determined to be of benefit to CWL. Using the results of the 2008 Study, CWL revised its DSM offerings. The following paragraphs discuss the current offerings.

2.2.1 Residential

1. Home Performance with Energy Star – a national program for existing homes that is designed to bring homes up to Energy Star standards. The utility has an extended loan program for participants and also offers rebates.

2. Air Conditioner or Heat Pump Rebates – incentives are based on the size and SEER of the system. The amount of the incentive is based on the amount of energy saved and the utility cost benefit.

3. Residential Loans – CWL offers electric customers low interest loans to make energy efficiency improvements. As approved by the Columbia City Council, the loan program is now only available to Home Performance participants so greater efficiencies are gained. Data has shown that loan customers finish more energy efficiency projects and save more energy than those that only take advantage of the rebate program. This program is funded by the electric utility's designated loan fund. The funds are paid back to the utility by the customers.

4. Online Energy Audit – CWL started a free online energy audit on the city's website in the fall of 2008. The average number of visitors each month was 162. Customers can conduct an assessment and receive recommendations based on the input. There is also an energy efficiency reference library.

5. Energy Audits – Columbia's free evaluation of a home or business provides energy and water efficiency tips specific for the location. Energy savings are harder to calculate for this program since it is not as in-depth as the Home Performance with Energy Star assessment.

6. New Home Energy Star Rebates – a national program in conjunction with the EPA's Energy Star program. Energy Star homes are 20 to 30 percent more efficient than standard homes. The amount of new homes being built in Columbia has gone down over the last several years so participation in this program has been small. For electric customers who meet Energy Star new home requirements, CWL offers a $1,000 rebate.

7. Tree Power – this program promotes energy conservation though energy efficient landscaping. Customers receive a landscape audit which indicates where they should plant their free 6- to 8-foot tall shade tree. Properly placed shade trees, at maturity, can reduce cooling costs by 30 percent.

8. Low Income Assistance –
   a. Energy efficiency for Columbia's low-income customers has been greatly assisted by the Central Missouri Community Action's weatherization program. Using federal funds, low-income residents of Boone County can qualify for a free weatherization.

b. Enhanced Home Performance with Energy Star – Enhanced Home Performance with ENERGY STAR Program (EHPwES) offers incentives of up to $2,500 for energy efficiency retrofits. This program is based on the energy efficiency modeling of the Home Performance with Energy Star, with adjusted incentives for income eligible households. (200 percent of Federal Poverty level and below). *.EHPwES* funding will be used in conjunction with funding from the Department of Energy to allow weatherization dollars to reach more distressed customers within the CW&L territory.

9. Window Air Conditioner Exchange Program – to reduce summer electric bills for low-income customers that use window air conditioning units, an exchange program was started in 2007. CWL collaborates with Central Missouri Community Action (CMCA) on this program. An income qualified person brings in an older, inefficient unit and is given a new, Energy Star rated window unit provided by the utility. The average cost of the unit is $170.

10. Building Codes – Both the Building Construction Codes Commission and the Environmental and Energy Commission reviewed the building code regulations and provided input to the City Council about the adoption of new codes. In March of 2011, the City adopted the 2009 International Building Code with amendments. Of particular note, the City also adopted Chapter 11 of the 2009 International Residential Code regarding energy efficiency essentially verbatim with very minor amendments.

2.2.2 Commercial

1. Leak Detection Program – this program helps customers (businesses) identify leaks so they can be prepared. It generally takes 2 to 4 days for an inspection in which 50 to 70 problems are found. Customer follow-up is poor. Staff is evaluating setting up a charge for this service then offering a rebate if the customer fixes the problems. This program is marketed through direct customer contact and some advertising.

2. Lighting Incentive Program – CWL encourages commercial customers to reduce their electric costs with incentives to increase their lighting efficiency.

3. Energy Assessments – CWL provides commercial energy assessments for commercial customers so savings can be identified.

4. Commercial Loans – CWL offers commercial electric customers low interest loans to make energy efficiency improvements. As approved by the Columbia City Council, the loan program requires detailed assessments.

5. Infrared Scans (Thermography) – this program helps commercial customers reduce the number of costly, unscheduled shutdowns and/or damage by detecting equipment failure in its early stages. Mechanical components, electrical cabinets, electrical distribution systems and building envelopes can also be inspected. It generally takes two days for an inspection in which 40 to 60 problems are found. The report is generated in five days. This program is marketed through direct customer contact and some advertising.

6. Building Operator Certification Program (BOC) – a professional development course for operations and maintenance staff working in public, institutional and commercial buildings. The classes are offered once a year through a partnership with the Missouri Department of Natural Resources and the Midwest Efficiency Alliance.

7. Energy Efficiency and Conservation Block Grants – This grant is for energy assessments of city buildings, funding the Office of Sustainability and funding energy efficiency improvements to city facilities. CWL staff gathered data and assisted the contractor during the 60 assessments.

8. Partnership with the University of Missouri – The Missouri Industrial Assessment Center (part of the Engineering Department of the University of Missouri) has conducted energy audits on several customers in the last 2 years. This partnership helps the utility save staff time, giving the students experience with onsite assessments, and customers are informed of ways to save energy. CWL facilitated and accompanied Missouri Industrial Assessment Center for six industrial customers.

2.2.3 Peak Reduction Programs

CWL has initiated Peak Reduction Programs designed to reduce electrical demand when needed by the utility. These programs are voluntary and offer incentives to participating customers.

1. Load Management – a residential and small commercial customer demand response program. The intent of the program is to reduce peak electric demand by controlling air conditioning loads when the cost of electricity is at its highest, typically on hot summer afternoons. Due to the cool weather, the switches were not activated in 2008 or 2009. The customer discount was raised in 2009 to 5 percent and reduced to 3 percent in 2010. On June 23, 2010 an all-switch test was

conducted and the kW reduction was 21,000 for two, 7 ½ minute cycle intervals. The temperature for that day was 94 degrees Fahrenheit.

2. Load Shedding Program – a peak electric load reduction program for large commercial and industrial customers that have demand levels of 250 kW or higher during the summer. As an incentive for participation, there is a monthly credit of $36/year for each kW of load shed. A maximum of 50 percent of the load is eligible for load shedding credits. Credits are paid to the customer in monthly credits, of $3/kW, starting with the October billing. When called to participate, these customers can reduce Columbia's load by 4.5MW.

2.2.4 Education

The CWL Utility Services Division has instituted a number of educational programs to provide awareness on energy conservation. These efforts include Weatherization workshops, broadcasting conservation tips on the Columbia Channel, presentations at civic groups, radio and other media releases. Announcement and program advertisement is sometimes printed on the bill envelope. Another significant education outreach from CWL is the Building Operators Certification (BOC) program. This is a professional development course for operations and maintenance staff working in public, institutional and commercial buildings. CWL offers a series of courses on the energy and resource efficient operation of buildings. Knowledge gained from completing the BOC program provides low to no-cost methods that improve energy savings.

2.3 EXISTING GENERATION RESOURCES

CWL receives energy from a variety of existing generation resources, which includes jointly and wholly owned coal-fired steam units, natural gas-fired combustion turbines, wind, and landfill gas facilities. The most significant change in capacity since the 2008 Study has been the acquisition of the balance of the Columbia Energy Center (CEC). The CEC is now totally owned and operated by CWL. Table 2-2 lists the existing generation resources and their capacities available to CWL. A description of each of the existing CWL resources is provided in the following paragraphs.

Table 2-2: Existing CWL Generation Resources

Unit	Description	Net Unit Nameplate Capacity (MW)
Bluegrass Ridge[1]	Wind	6.3
NextEra Crystal Lake 3 [1]	Wind	10.5
Columbia & Ameresco	Landfill Gas	5.0
Distributed Generators	Diesel Generation	12.5
Columbia Energy Center	Combustion Turbine	144.0
CWL Turbine 5[2]	Coal-Fired Steam	16.5
CWL Turbine 6	Combustion Turbine	12.5
CWL Turbine 7[2]	Coal-Fired Steam	22.0
CWL Turbine 8	Gas-Fired Steam	35.0
Iatan II	Coal-Fired Steam	20.0
Nearman Creek(3)	Coal-Fired Steam	20.0
Prairie State	Coal-Fired Steam	50.0
Sikeston	Coal-Fired Steam	66.0
	Total Nameplate MW:	**420.3**
	Total MW with Wind Credit Adjustment	**408.2**

1. Nameplate capacity-Accredited at 13.3% for calendar year 2013.
2. CWL Turbines 5 and 7 scheduled to be retired in 2015.
3. Contract Termination May 1, 2013

2.3.1 Municipal Power Plant

CWL has three operable boilers and a combustion turbine at its Municipal Power Plant. The boilers are connected to a common steam header which operates at 850 psig and 900°F. Turbines 5 and 7 are bituminous coal-fired steam turbines rated at 16.5 and 22, MW, respectively. Turbine 8, a gas-fired steam turbine rated at 35MW, is the newest of the three steam turbines at the plant, installed in 1970. These turbines are normally used only during the summer and winter seasonal peaks. The decision on whether to retire these units is under review by CWL. For study purposes, it was considered that turbines 5 and 7 were retired at the end of 2015, to be consistent with the 2008 IRP. Turbine 6, installed in 1963, is a natural gas -fired combustion turbine rated at 12.5MW. Turbine 6 is normally run only during daytime hours at peak load times.

2.3.2 Sikeston

The Sikeston power facility is owned and operated by the City of Sikeston, Missouri and has a net unit capacity of 222MW and a net unit heat rate of 11,084 Btu/kWh. CWL has a long-term power purchase agreement (PPA) with Sikeston to acquire 66MW of capacity and associated energy from the Sikeston facility. Under the terms of the agreement, CWL is required to take delivery during each contract year of a minimum amount of energy which is partly based on the load factor of the CWL electric utility system. Power costs are based on the costs of debt service, operation, maintenance, administration and general expenses over the contract year. The contract is a life of unit contract and the unit is expected to remain available through the study period.

2.3.3 Nearman Creek

CWL determined to terminate this contract and the final deliveries under the agreement will be in April 2013.

2.3.4 Iatan Unit II

Kansas City Power & Light (KCP&L) currently operates two PRB coal-fired units at its Iatan station. The new 850MW Unit 2 was commercially available in 2010. The unit is a high efficiency, coal-fired power plant using emission control equipment designed to meet current clean air requirements. Because the site is located at an existing power plant facility, operational efficiencies will help lower ongoing operating costs. Columbia has a long-term PPA with the Missouri Joint Municipal Electric Utility Commission (MJMEUC) to acquire 20MW of capacity and associated energy from the Iatan Unit 2 facility. The contract is a life of unit contract and the unit is expected to remain available through the study period.

2.3.5 Prairie State Energy Campus

Prairie State Energy Campus (PSEC) is a 1,500MW electric generation facility in southern Illinois that is fueled by coal produced from an adjacent underground mine. The project was developed by Peabody Energy. Both units at the PSEC went commercial in 2012. Because the facility is a mine mouth unit, it should provide a low-cost fuel option for future CWL energy requirements. Emission control technologies meet federally mandated requirements. CWL has a long-term PPA with MJMEUC to acquire 50MW of capacity and associated energy from the PSEC facility. The contract is a life of unit contract and the unit is expected to remain available through the study period.

2.3.6 Renewable Resources

In November 2004, the City of Columbia approved a renewable energy ordinance for the city's power supply portfolio. The ordinance mandates CWL to purchase increasing levels of energy from renewable resources starting in 2008. In response to the RPS Ordinance, CWL has secured contracts from several qualifying renewable generating resources for wind and landfill gas energy. CWL has a long-term purchase agreement with AECI to acquire the energy from three wind turbines (6.3MW net capacity) at the Blue Grass Ridge Wind Farm in Gentry County, Missouri. CWL has also purchased 10.5MW of net capacity from the NextEra Crystal Lake 3 Wind Farm. The amount of electricity Columbia will receive each year is variable, depending on the amount of wind. Capacity from the wind farms is accredited at 13.3 percent of the nameplate value.

CWL also has long-term purchase agreement to receive landfill gas from facilities in Jefferson City. CWL owns and operates a landfill gas plant at the Columbia Landfill.

The energy from all qualifying renewable resources amounts to nearly 8 percent of CWL energy requirements in 2012.

CWL also supports expansion of solar energy within the city. The addition of solar energy is performed under two basic programs. A net metering program allows for the addition of a solar resource on the customer side of the meter. The energy produced by the resource is used to offset energy purchased from CWL. Energy provided by the resource in excess of what is being consumed is output to the CWL distribution system for use by others. The net metering program is aimed at residential customers. The program provides a rebate of $500 per kW. There are currently six residential customers participating with a nameplate capacity of 1.9kW. The units are assumed to provide approximately 37.3MWh per year.

The commercial sector is provided an opportunity to participate in solar energy through the Solar One program. CWL enters into power purchase agreements with commercial customers who install a solar system. CWL then sells the energy to customers who pay a surcharge for the solar energy produced. CWL also entered into an agreement with Free Power Company (FPC) in December 2010. This agreement required FPC to install solar resources on city property. An estimated nameplate capacity of 9MW and 12,000MWh are expected from this program. It is expected that the program with FPC and the Solar One program will eventually be merged into a single program.

Table 2-3 provides an overview of the requirements for renewable energy under the Columbia RPS ordinance. The major sources of the renewable energy come from the wind power purchase agreements and the landfill gas units. The solar energy provided under the net metering program is a very small component of the total energy provided. Solar energy is expected to provide approximately 0.50GWh under the commercial Solar One and FreePower programs in 2013. As seen, additional renewable energy will be required during the study period.

Table 2-3: CWL Energy and RPS Requirements

Year	Total Energy (GWh)	RPS Ord. Energy (%)	RPS Ord. Energy (GWh)	Blue Grass WF Energy (GWh)[1]	NextEra WF Energy (GWh)[2]	Ameresco LF Energy (GWh)[3]	Columbia LF Energy (GWh)[3]	Total RPS Energy (GWh)	Existing Resource Surplus/(Shortage) (GWh)	New Solar (MW)	New Solar (GWh)[4]	New Wind (MW)	New Wind (GWh)[5]	New Resource Surplus/(Shortage) (GWh)
2013	1,251	5.00%	62.55	15.45	41.39	25.23	18.00	100.07	37.52	1.0	1.39		0	38.92
2014	1,278	5.00%	63.90	15.45	41.39	25.23	23.65	105.72	41.82	2.0	2.79		0	44.61
2015	1,304	5.00%	65.20	15.45	41.39	25.23	23.65	105.72	40.52	4.0	5.57		0	46.09
2016	1,329	5.00%	66.45	15.49	41.50	25.30	23.65	105.95	39.50	6.0	8.36		0	47.85
2017	1,358	5.00%	67.90	15.45	41.39	25.23	23.65	105.72	37.82	8.6	12.00		0	49.83
2018	1,393	10.00%	139.30	15.45	41.39	25.23	23.65	105.72	(33.58)	8.6	12.00	5	14.24	(7.33)
2019	1,427	10.00%	142.70	15.45	41.39	25.23	31.54	113.61	(29.09)	8.6	12.00	10	28.48	11.39
2020	1,461	10.00%	146.10	15.49	41.50	25.30	31.62	113.92	(32.18)	8.6	12.00	10	28.48	8.30
2021	1,495	10.00%	149.50	15.45	41.39	25.23	31.54	113.61	(35.89)	8.6	12.00	10	28.48	4.59
2022	1,532	10.00%	153.20	15.45	41.39	25.23	31.54	113.61	(39.59)	8.6	12.00	10	28.48	0.89
2023	1,569	15.00%	235.35	15.45	41.39	25.23	31.54	113.61	(121.74)	8.6	12.00	45	128.16	18.42
2024	1,607	15.00%	241.05	15.49	41.50	25.30	31.62	113.92	(127.13)	8.6	12.00	45	128.16	13.03
2025	1,645	15.00%	246.75	15.45	41.39	25.23	31.54	113.61	(133.14)	8.6	12.00	45	128.16	7.02
2026	1,663	15.00%	249.38	15.45	41.39	25.23	31.54	113.61	(135.77)	8.6	12.00	45	128.16	4.40
2027	1,695	15.00%	254.23	15.45	41.39	25.23	31.54	113.61	(140.62)	8.6	12.00	50	142.40	13.78
2028	1,727	15.00%	259.08	15.49	41.50	25.30	31.62	113.92	(145.16)	8.6	12.00	50	142.40	9.24
2029	1,760	15.00%	263.94	15.45	41.39	25.23	31.54	113.61	(150.33)	8.6	12.00	50	142.40	4.07
2030	1,792	15.00%	268.79	15.45	41.39	25.23	31.54	113.61	(155.18)	8.6	12.00	55	156.64	13.46

[1]Blue Grass Ridge Wind Farm assumed to have 28% capacity factor

[2]NextEra Crystal Lake Wind Farm assumed to have 45% capacity factor

[3]All landfill gas energy assumed to have 90% capacity factor except for CLF 2013-2018

[4]New solar resources assumed to have 15.9% capacity factor

[5]New wind resources assumed to have a 32.5% capacity factor

2.3.7 Columbia Energy Center

The Columbia Energy Center was purchased from Ameren Generating Company. The CEC consists of four simple cycle, 36MW combustion turbines (144MW net capacity) located within Columbia city limits. CWL is now responsible for all ownership, fuel and maintenance costs. CEC is typically dispatched only during peak hours.

2.3.8 Other Resources

CWL leases or owns capacity shares in several other generating units amounting to 12.5MW of diesel generators. It is assumed that these generation resources are available to CWL throughout the study period.

2.3.9 Market Capacity and Energy

The interconnection CWL has with AmerenUE (Union Electric) permits it to access the MISO utility energy market outside of its own service territory. This market access permits CWL to purchase standby reserves, maintenance energy, firm and non-firm capacity and also permits energy sales and economy energy transactions. These transactions permit CWL to optimize the use of its electrical generation.

In addition to the above transaction types, CWL can contract for capacity and associated energy with another party. These arrangements are called bilateral contracts. Bilateral transactions in the MISO market are delivered over the MISO transmission system. The delivery cost for the bilateral energy is priced as the difference between the injection node and the CWL load node. The market will allow transactions of the energy from the resource to the value of the resource that is deemed deliverable through the MISO market deliverability tests.

Contracts with entities located outside of the MISO area must have transmission delivery arranged across the systems between the selling entity and CWL. This involves requesting the service from the respective utility. The utilities involved would perform analyses to determine if transmission capacity is available for delivery of the requested capacity and energy. Should improvements be necessary to the transmission system for delivery of the requested contract, then CWL would potentially be responsible for paying for the cost of the upgrades.

2.4 BALANCE OF LOADS AND RESOURCES

The CWL service territory is located within the MISO reliability region. According to CWL, MISO requires a 14 percent reserve margin above the peak demand of the utility. Following this guideline, reserve requirements for the purposes of this study were calculated as being 14 percent of peak load less firm contract purchases.

2.4.1 Demand/Capacity Balance

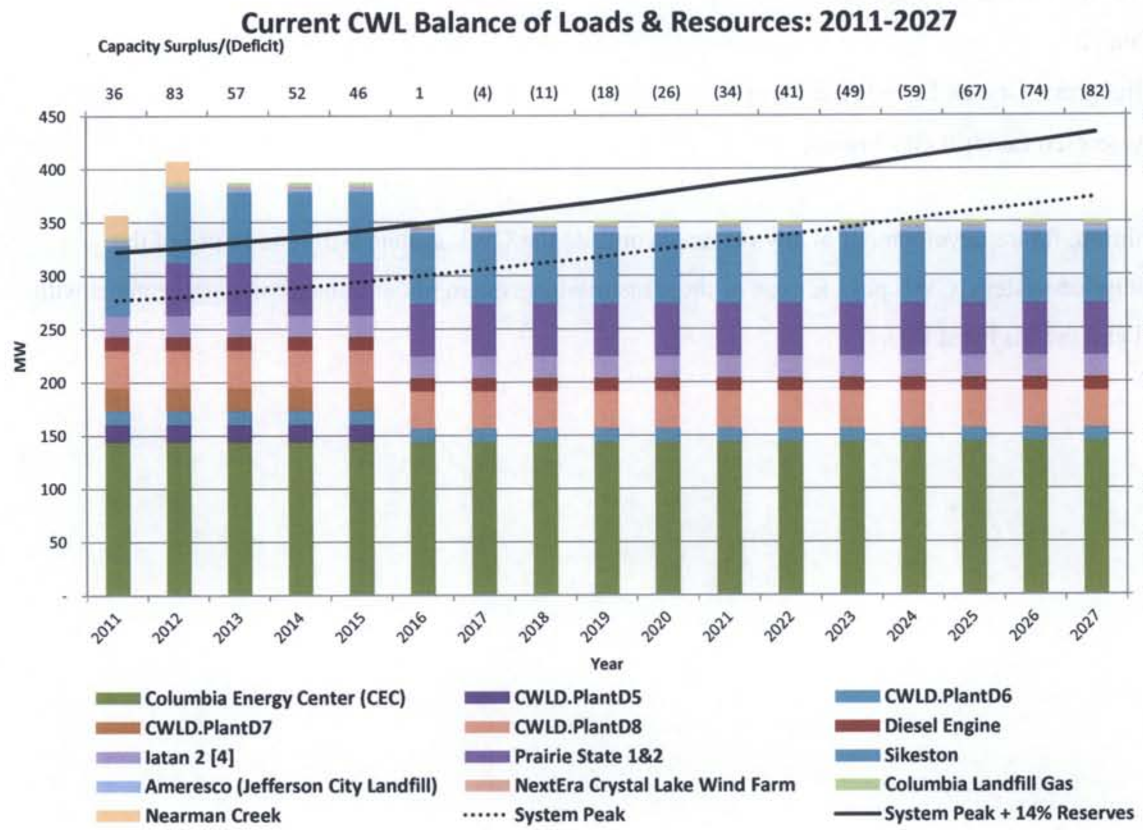
Figure 2-1 shows a balance of loads and resources for the CWL system using the previously described load forecast and existing generation and purchase resources assuming approximately 15 percent accredited capacity of nameplate wind. A utility is also required to maintain reserves to meet unit outages and planning uncertainties. Prudent utilities also use reserves to meet economic growth larger than expected.

CWL operates in the Midwest Independent Transmission System Operator, Inc. (MISO) region. MISO requires that members in the CWL area maintain a reserve level above peak load less firm purchases. The MISO is modifying the reserve margin construct for the load serving entities (LSE) in its market. MISO is moving to the use of unforced capacity values (UCAP) for determination of the generation MW available to an LSE. A UCAP value for generation capability involves multiplying the generator tested output capacity (ICAP) by a forced outage factor (XEFORD). The XEFORD is based on historical generator availability data (GADS) for the specific unit. MISO also has EFORD class averages for use on new facilities with no operating history. The intent of this change is to make maintenance a priority for the units so they are as available as possible.

The determination of reserve margin levels for an area considers the load, generation and the probability that the generation would be able to serve load. The use of the ICAP values in determination of the reserve margins required the forced outage probability of the units be considered in the loss of load probability calculations. This approach resulted in a reserve margin requirement typically in the range of 13 to 15 percent for most of the NERC regions. When using UCAP, this probability has been incorporated into the determination of the available MW to meet load. The net effect of using UCAP in the reserve margin determination is to arrive at a lower percentage reserve margin level to maintain the same level of loss of load probability. For purposes of this analysis, Burns & McDonnell and CWL determined to remain with the earlier ICAP approach to determining reserves and used the previous 14 percent reserve margin level required by MISO. Future resource planning studies should review the continued use of this approach as MISO migrates towards the UCAP based reserve requirements.

As indicated in this figure, the CWL system is projected to have a capacity deficiency beginning in 2017 with its existing mix of power supply resources, with the deficiency projected to grow over time.

Figure 2-1: Current CWL Balance of Loads and Resources, 2011-2027



2.4.2 Energy Sources

CWL obtains the majority of its energy from the MISO market at its load node. This energy is a mix of energy from CWL's resources, market purchases and renewable energy sources external to the CWL system. The balance of energy is provided by resources internal to the CWL system.

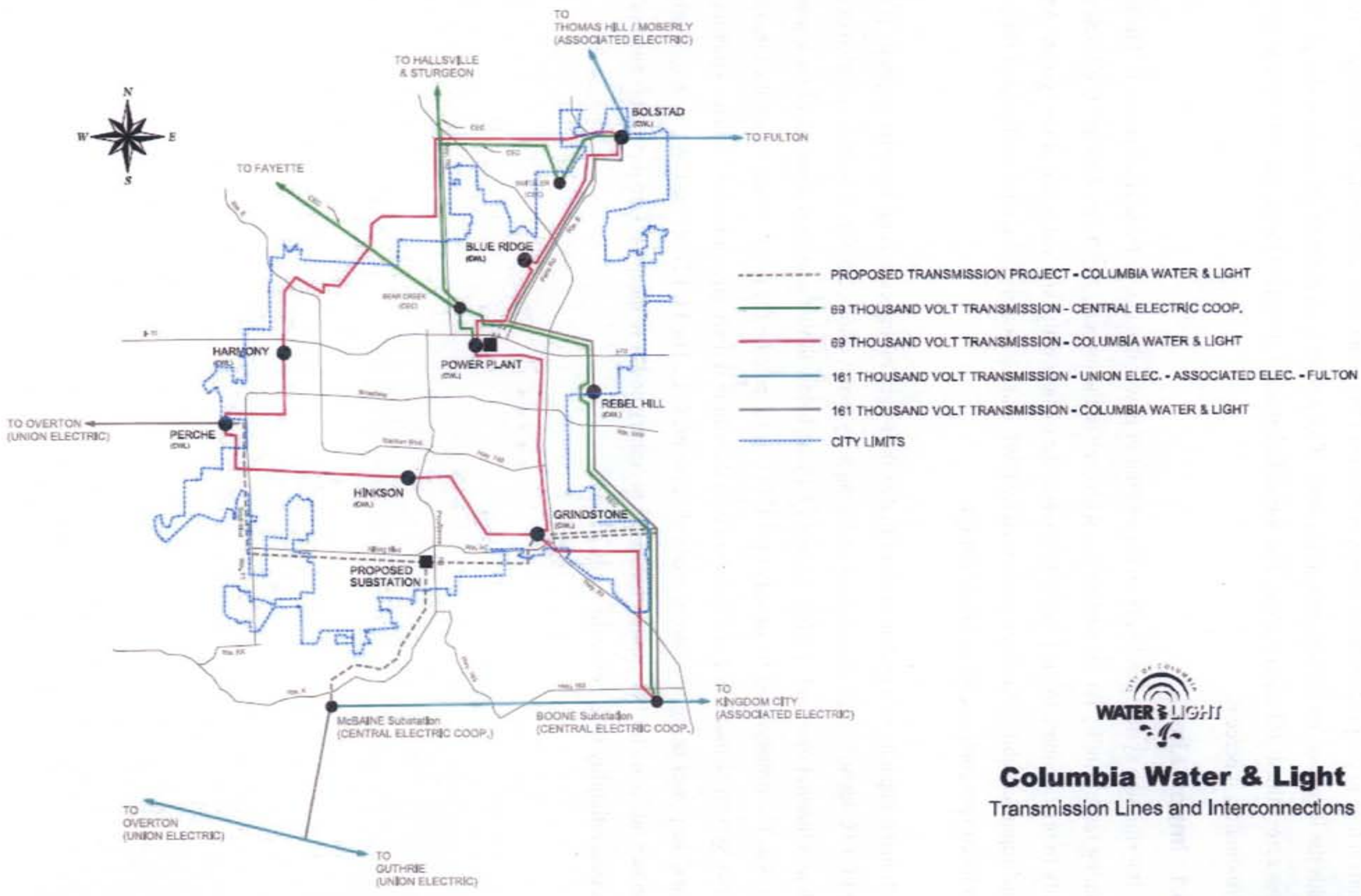
2.5 TRANSMISSION ISSUES

CWL imports energy into its service territory to meet its load via transmission facilities owned and operated by other utilities. Direct interconnections are made with Ameren and AECI at substations around the CWL service area. These interconnections are made at the 161kV and 69kV level. Figure 2-2 provides an overview of the system and the major interconnection locations. In addition to market energy, the system is or will be used to import power from the following CWL resources:

- Sikeston
- Prairie States Energy Center
- Iatan 2
- Bluegrass, Crystal Lake Wind Farms
- Ameresco Landfill Gas Project

In addition, future development of any resources outside the CWL system will require use of the transmission system. CWL pays for use of the transmission system under transmission agreements with AECI and the Midwest ISO.

Figure 2-2: CWL Transmission System



An advantage to the production of energy within the CWL area, such as the solar PV energy, is that it avoids the losses across the transmission system. If located in a net metered situation, it also avoids the losses across the distribution system. The transmission and distribution losses are estimated to be approximately 4 percent.

2.5.1 Import Limits

The transmission system has limits on the amount of power that can be transferred across it. The overall planning responsibility for the system lies with each of the owners, AECI and Ameren. CWL has the ability to provide input to the process to provide the owners with expected usage of the system. Analysis of the import capability has been performed by CWL and the owners to identify the limits of the system with its current components and their ratings.

The transfer capacity of a system is identified as the First Contingency Total Transfer Capacity (FCTTC). The FCTTC identifies the maximum transfer capacity that is allowed before a system violation occurs, such as a thermal overload or a bus voltage dropping below limits, when a component of the system is removed. The process used to identify the FCTTC is to increase the power being transmitted into an area, remove system elements one at a time and then determine if there any violations. When a violation occurs, the power being transferred establishes the FCTTC. The FCTTC of the CWL system is projected to remain adequate for the importation of the necessary power to meet CWL requirements and maintain expected reliability levels over the study period.

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SECTION 3.0

SUPPLY SIDE ANALYSIS

3.0 SUPPLY SIDE ANALYSIS

The development of a power resource analysis requires creation of a mix of resources to evaluate. This part of the report describes the options reviewed, costs for the options, and the detailed analysis performed on the selected options. A summary of the major assumptions used in the 2013 Update can be found in Appendix A.

3.1 GENERAL ASSUMPTIONS

The supply side analysis began with the development of the assumptions for the various resources considered as applicable for CWL. The following general assumptions are applicable to the supply side analysis:

- The 2013 Update study period covers the years 2013 through 2030.
- CWL must maintain reserves of 14 percent above peak load throughout the study period.
- CWL retires Units 5 and 7 at the Municipal Power Plant in 2015.
- The 2010 hourly load was used as the basis for the load growth projections provided by CWL.
- Budgets and forecasts associated with the current CWL assets were escalated at their historical trend or inflation over the study horizon.
- The discount rate for CWL for financing terms was 4.0 percent, with resources financed over 20 years.

Details of the various assumptions can be found in Appendix A.

3.2 FUEL CONSIDERATIONS/FORECASTS

Many of the generating resources considered in the supply side analysis require an associated fuel for power generation. The analysis utilized gas, coal, and spot market pricing to help determine production costs for each of the various supply alternatives considered. The following paragraphs discuss each of the various fuel forecasts used in this analysis.

3.2.1 Coal

Coal forecasts were developed for the following facilities for use in the analysis.

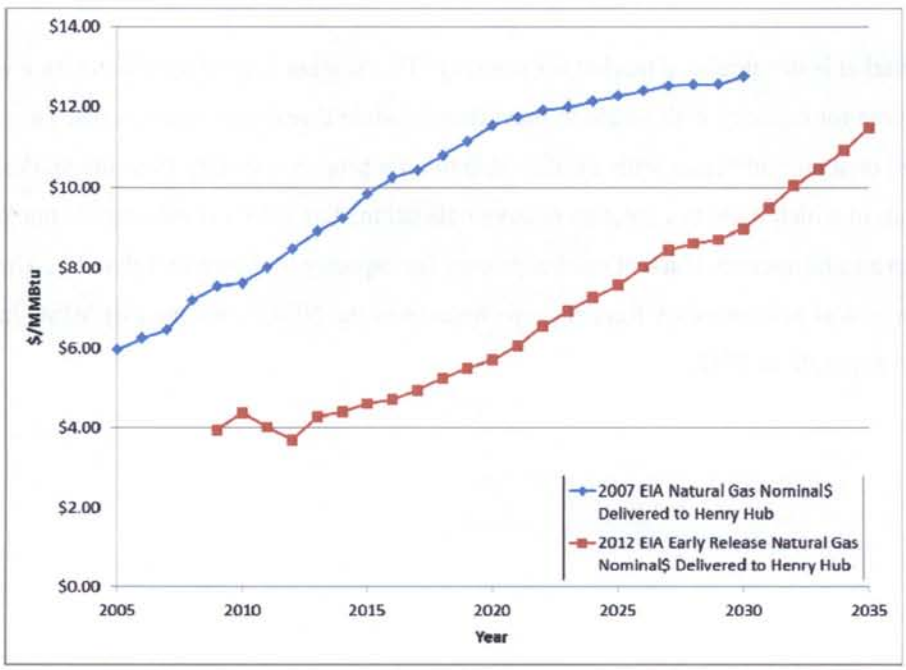
- Generic coal forecast for adjusting MISO market energy
- Municipal Power Plant

- Prairie State Facility

3.2.2 Natural Gas

The assumption for the cost of natural gas has been one of the most dramatic changes in resource plans developed since 2008. The rapid rise of hydraulic fracturing (fracking) in the drilling process for oil and natural gas in the United States has led to dramatic changes in the amount of natural gas available in the US. This supply glut has created pricing of natural gas well below the projections provided by various sources in the 2008 period. Figure 3-1 provides a comparison of the forecast for natural gas used in the 2008 Study and forecast data used in this 2013 Update. Both of the forecasts were developed using data from the Energy Information Agency.

Figure 3-1: EIA Natural Gas Forecast



As seen, the forecast for the 2008 Study was approximately twice what the current values of natural gas are for 2013. The price of natural gas has caused a significant increase in the amount of electricity produced with natural gas in 2012, displacing electricity produced by coal. Due to the difficulty of permitting new generating units fired by coal, virtually all new generating resources are fired on natural gas.

3.2.3 Nuclear

As in the 2008 Study, there are no proposed nuclear options in which CWL could consider participation. Therefore, no nuclear cost or fuel forecasts were prepared or used in this study. The advancement of the nuclear generation development has also been significantly delayed due to the current and expected natural gas market. At the projected natural gas fuel prices and the cost of gas-fired generation capacity, the construction of new nuclear fueled generation resources is not economical.

3.2.4 Market

The spot market energy price forecast was developed using the hourly day-ahead LMP pricing of the Cinergy (Indiana) Hub in MISO from January through December 2010. On-peak energy prices for 2013 and beyond were projected using the same underlying annual escalation as the EIA natural gas forecast throughout the study period. Similarly, off-peak energy prices followed the coal forecast escalation. The entire energy market price forecast can be found in the study assumptions found in Appendix A.

The MISO market is developing a market for capacity. This market is used by utilities on a voluntary basis as a source for capacity with which to meet their Module E reserve requirements. The market has been operated on a monthly basis with a utility able to only procure capacity from the market for any specific month in which it did not meet its reserve obligation. The MISO is moving the market from a monthly to an annual auction. Current market pricing for capacity is shown in Table 3-1. The values are far below the cost of new capacity. Recent projections from the NERC indicate that MISO had a 43 percent reserve margin in 2012.

Table 3-1
MISO Capacity Market Clearing Prices 2012

Planning Year	Month	Auction Clearing Price ($/APRC)	Total Amount of APRCs Bid into the Auction	Total Amount of APRCs Offered into the Auction	Total Amount of APRCs Cleared in the Auction
PY2012-2013	Jun	0.40	1,232.7	7,870.9	1,227.6
PY2012-2013	Jul	50.00	1,693.2	2,601.1	1,058.0
PY2012-2013	Aug	10.00	1,058.3	5,250.1	1,057.2
PY2012-2013	Sep	0.15	812.6	14,828.1	812.5
PY2012-2013	Oct	0.14	1,045.6	26,282.3	1,045.4
PY2012-2013	Nov	0.10	980.9	23,822.2	980.7

To give perspective to the above prices, the annual cost of capacity at the July price would equate to $0.60 per kW-yr.

In addition to the MISO market, CWL can procure capacity and associated energy on a bilateral basis through power purchase agreements (PPA). These PPAs can be provided under a range of terms and conditions. For instance, they can be used as a pure call option whereby the demand charge is the price of the call for the ability to take the energy at a certain price. They can also be structured where the customer is required to take a certain amount of energy per time period for a certain capacity and energy price. CWL can evaluate these PPAs as it would acquisition of any resource.

3.3 TRADITIONAL OPTIONS

For utilities in the MISO market, owned, traditional generation resources (and PPAs) are used to satisfy the capacity obligations of the utilities, to act as a revenue source when the bid energy price of the resource clears the MISO market and as a hedge against MISO market prices above the energy cost of the resource. Due to these uses, many utilities procure low capital cost resources that may provide some relief from high energy prices.

The traditional resource options available to utilities of all types are being significantly restricted due to environmental regulations. New regulations have essentially removed coal fueled power plants as an option. Essentially all of the traditional resource options are fired by natural gas. CWL has an ongoing review of the use of biomass at the Municipal Plant. Current work on obtaining a fuel supply at a price that would allow ongoing operations of the solid fuel boilers at the plant is being performed by CWL. The results of this effort will have a slight impact on the amount of capacity required. The review of the biomass future at the Municipal Plant was not included within this study. Should the fuel source and combustion economics prove favorable, the need for additional capacity may be delayed from the dates indicated in the following analysis. The following paragraphs describe the traditional resources included in the 2013 Update.

The estimates developed for the CEC expansion and other options considered are based on Burns & McDonnell's experience with other expansion projects. Due to the unique attributes associated with any specific greenfield or expansion project, the assumptions developed herein are considered adequate for use in the 2013 Update, but will require more detailed analysis prior to a final determination of whether or not to actually pursue an option.

3.3.1 CEC Conversion to Combined Cycle

The basic principle of a combined cycle gas turbine (CCGT) plant is to utilize natural gas to produce power in a gas turbine (GT) and also use the hot exhaust gases from the GT to produce steam in a Heat Recovery Steam Generator (HRSG). The use of both gas and steam turbine cycles: Brayton and Rankine, in a single plant to produce electricity results in high conversion efficiencies and low emissions.

The CEC consists of four existing simple cycle combustion turbines rated 36MW. The addition of the steam portion of the combined cycle expansion would require the addition of a heat recovery steam generator, the steam turbine and the electric generator. It was assumed for purposes of this analysis that the site had sufficient clearances to allow construction of the combined cycle expansion. It was further assumed that a separate HRSG would be provided for each CT which would then feed a header system to supply steam to a single steam turbine/generator. The net electrical output was assumed to be 206MW in total, base loaded (with duct firing capability the total output would be 294MW). One fourth of this capacity could be obtained with dispatch of each CT. An additional transformer and switchyard connection would also be required.

3.3.1.1 Constructability and Permitting

For purposes of this study, construction of the CEC expansion would have a Commercial Operating Date (COD) of no earlier than 2016. A general review of site plans was performed by Burns & McDonnell of the CEC. Although it appears there is sufficient space to add the combined cycle portion described above, no site verification has been performed. Also, it appears that permitting of the existing turbines allows 400 hours of operation per turbine during the period from May through September. This would limit the utilization of a combined cycle asset constructed at the site unless the permit was revised.

Natural gas-fired generation resources would be equipped with emission control technology to meet currently required emission regulations. The following are the assumed emission rates of criteria pollutants for this supply alternative:

- NO_X: 0.009 lbs/MMBtu
- CO: 0.006 lbs/MMBtu
- CO_2: 120 lbs/MMBtu

3.3.1.2 Performance and Cost Assumptions

The expansion of the CEC with a natural gas-fired CCGT option was assumed to have a net electrical increase in the CEC output of approximately 62MW (to a total net plant capacity of 206MW) and an operational heat rate of 8,140 Btu/kWh. In 2012$, variable and fixed O&M for this alternative was assumed to be $4.40/MWh and $12.00/kW-yr, respectively for the total net plant capacity. Assuming a 2016 COD and 2016$, the total project costs, including Owner's and Interest During Construction (IDC), was an estimated $2,417/kW (based on the full baseload plant output of 206MW). Please refer to Appendix A for a complete summary of assumptions used for all of the supply options considered in this study.

3.3.2 Local Simple Cycle

Typically, simple cycle generation options are used to provide peaking power due to their fast load ramp rates and relatively low capital costs. Simple cycle generation based on gas turbine and reciprocating engine technologies is a widely used and mature technology. These units are typically fired using natural gas as the primary fuel. Some units are provided with oil as a backup to interruption of the natural gas. The gas turbine (Brayton) cycle is one of the most efficient cycles for conversion of gaseous fuels to mechanical power or electricity. However, the units typically have higher dispatch costs when compared with combined cycle and coal-fired technologies. Gas turbines can have capacity ratings of kW for micro-turbines to units of 200MW nominal. Reciprocating engines can have capacities of watts up to approximately 20MW. The larger reciprocating engines typically have better heat rates than the combustion turbines. Peaking resources offering dispatch flexibility and capacities at or below 50MW were considered the best alternatives for peaking resources to be evaluated in this study.

3.3.2.1 Constructability and Permitting

It was assumed that any simple cycle capacity constructed would be located at a site within the CWL service territory. For purposes of this study, construction of a simple cycle resource would have a COD of no earlier than 2015. For purposes of this analysis, MW scale reciprocating engines were considered due to the flexibility of being able to add relatively small MW quantities to better match expected load growth, their dispatch attractiveness in the MISO market and their efficiency advantage over combustion turbines.

Natural gas-fired generation resources would be equipped with emission control technology to meet currently required emission regulations. The following are the assumed emission rates of criteria pollutants for the reciprocating engine supply alternatives:

Assumed reciprocating engine emission rates:

- NO_X: 0.018 lbs/MMBtu
- CO: 0.034 lbs/MMBtu
- CO_2: 120 lbs/MMBtu

3.3.2.2 Performance and Cost Assumptions

A local natural gas-fired simple cycle option within the CWL service territory was assumed to have a net electrical output of 9.14MW per engine for the reciprocating engine option. This alternative assumed a block of six reciprocating engines was installed for a total capacity of 54.6MW. The operational heat rates of the units are 8,780 Btu/kWh. In 2012$, variable and fixed O&M for the reciprocating engine alternative was assumed to be $6.10/MWh and $16.17/kW-yr, respectively. Assuming a 2015 COD and 2015$, the total project costs, including Owner's and IDC, was an estimated $1,660/kW for the reciprocating engine alternative based on 54.6MW. Please refer to Appendix A for a complete summary of assumptions used for all of the supply options considered in this study.

3.3.3 Large Combined Cycle

The basic principle of a combined cycle gas turbine (CCGT) plant is to utilize natural gas to produce power in a gas turbine (GT) and also use the hot exhaust gases from the GT to produce steam in a Heat Recovery Steam Generator (HRSG). The use of both gas and steam turbine cycles: Brayton and Rankine, in a single plant to produce electricity results in high conversion efficiencies and low emissions. For this evaluation, a large 1x1 CCGT plant was considered with a total plant output near 300MW baseload.

In order to be able to use the advantages of a large combined cycle unit, CWL would have to share in a joint owned project, similar to the joint participation in units such as Sikeston and Iatan II. It is likely that such a unit would not be located within the service area of CWL.

3.3.3.1 Constructability and Permitting

It was assumed that large combined cycle capacity constructed would be located outside of CWL service territory. For purposes of this study, construction of a combined cycle resource would have a COD of no earlier than 2016 and would likely require another utility to take the lead on the development and construction of the unit due to the unit's large size. CWL could potentially purchase capacity and energy from a percentage of the unit.

Natural gas-fired generation resources would be equipped with emission control technology to meet currently required emission regulations. The following are the assumed emission rates of criteria pollutants for the combined cycle supply alternatives:

Assumed CCGT emission rates

- NO_X: 0.009 lbs/MMBtu
- CO: 0.006 lbs/MMBtu
- CO_2: 120 lbs/MMBtu

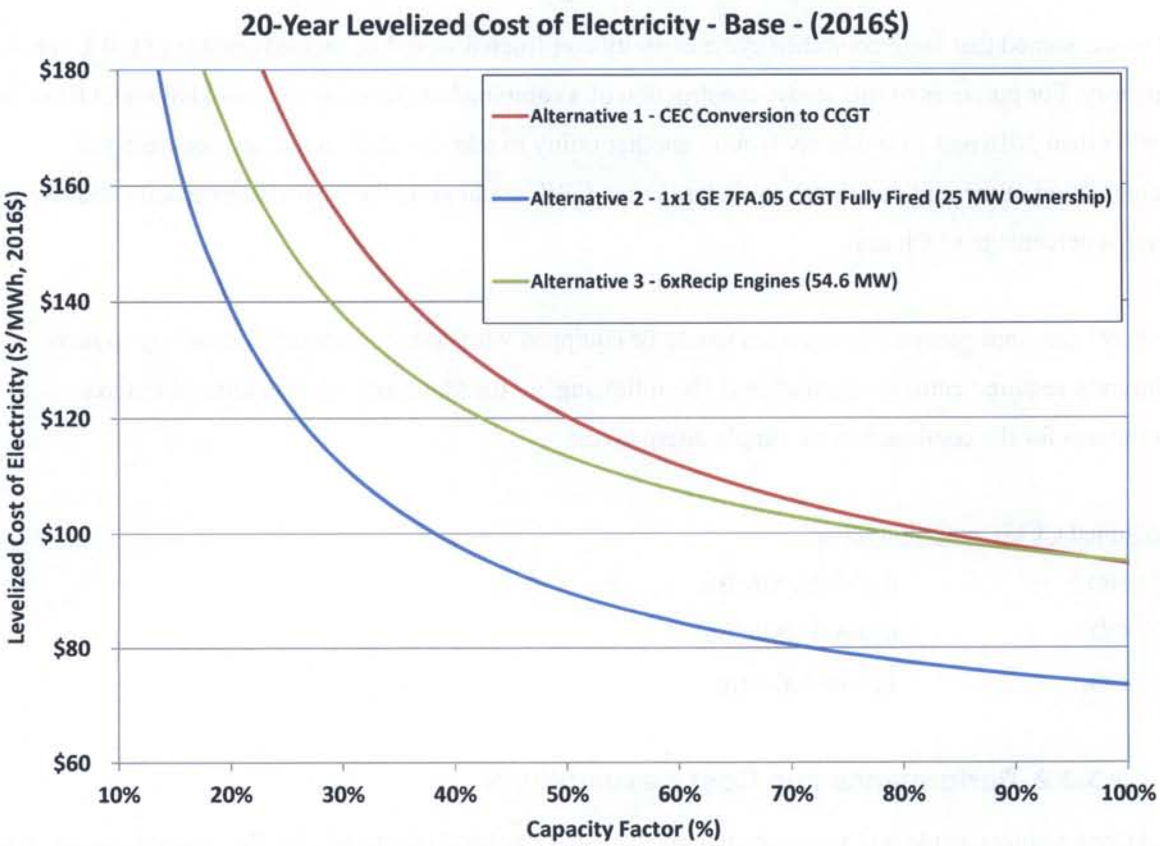
3.3.3.2 Performance and Cost Assumptions

A large combined cycle unit was assumed to have a net electrical output of 289.8MW based loaded. The operational heat rate of the unit is approximately 6,850 Btu/kWh (base loaded). Combined cycle units also have the ability to increase output through duct burning. The addition of duct burner capability would increase the capacity by another 91.7MW with an incremental heat rate of 8,310 Btu/kWh. In 2012$, variable and fixed O&M for the lager CCGT alternative was assumed to be $2.60/MWh and $15.00/kW-yr, respectively. Assuming a 2016 COD and 2016$, the total project costs, including Owner's and IDC, was an estimated $1,520/kW for the large CCGT alternative (based on base load output of 289.8MW). Please refer to Appendix A for a complete summary of assumptions used for all of the supply options considered in this study.

3.3.4 Alternative Levelized Cost of Electricity Evaluation

To provide a preliminary screening analysis of the supply side alternatives, Burns & McDonnell performed a levelized cost of electricity (LCOE) evaluation. Burns & McDonnell determined the 20-year LCOE across varying capacity factors for each alternative including debt service costs, variable and fixed O&M costs, and fuel costs. Figured 3-2 presents the LCOE for each of the alternatives.

Figure 3-2: Levelized Cost of Electricity Evaluation



As presented in Figure 3-2, the large CCGT alternative provides a lower LCOE for all capacity factors between 10 to 100 percent compared to the CEC conversion to CCGT and the reciprocating engines based on the assumptions used herein. The large CCGT alternative is estimated to be lower cost due to its lower heat rate and lower capital cost investment due to the large economies of scale. However, CWL would not be able to develop and construct a large CCGT option solely on its own and would be dependent on participation from other utilities. The CEC conversion to CCGT operation is slightly higher in cost than the reciprocating engine alternatives across the varying capacity factors.

3.4 POWER PURCHASE AGREEMENTS

Utilities can purchase capacity and energy in firm and non-firm contracts or purchase long-term capacity in generation facilities, similar to CWL contracts for several existing resources. Both of these options depend on the availability of excess capacity in the area. For CWL, capacity should be located within the CWL or MISO market to reduce the costs of delivery and potential for system constraints. Under the proposed MISO capacity construct, capacity would preferably be located in MISO Resource Zone 5.

Please refer to Appendix A for a complete summary of assumptions used for all of the supply options considered in this study.

3.5 STRATEGIST ANALYSIS

This part of the report addresses the various resource planning scenarios that were developed and analyzed using Strategist and describes the results of the analysis. The Strategist model is a resource portfolio optimization model that allows an analysis of several different resources with a variety of characteristics. The model selects the lowest cost combination of capacity amounts and in-service dates based on the performance and construction costs provided. In developing the scenarios, consideration was given to the existing resources discussed in Section 2 as well as various new resource options discussed previously in this section.

3.5.1 Portfolio Selection

The resource scenarios were modeled and simulated using the Strategist resource optimization software. The model used the assumptions of the resources as described previously in this section to determine the optimal portfolio of resources to meet the energy needed. In addition to the supply resources outlined previously in this section, when the supply resources were not available or economical, a market capacity resource was used to maintain reserve margins throughout the study period. This market capacity resource was modeled as a temporary supply resource, expiring at the end of each year. The model provided a net present value of costs for thousands of portfolio options.

In order to evaluate the economic impacts of certain resources, Burns & McDonnell forced the model to accept certain generating resources in some scenarios. There were essentially two futures considered with the resources available. The first was the partner future which considered participation in a large combined cycle unit. The other was the CWL control future of using reciprocating engines or adding the combined cycle expansion to the CEC. For purposes of the Strategist analysis, the reciprocating engine resource was used in the modeling due to the close LCOE of the CEC combined cycle expansion and the reciprocating engines. Within the range of assumption uncertainty for these two approaches, they were considered essentially equal for purposes of the portfolio analysis when comparing the partner future to the CWL control future.

The results of the Strategist analysis using the base assumptions are shown in Table 3-2. Each of the two futures included hundreds of portfolio combinations. The associated 2013$ NPV of the lowest cost portfolio for each scenario is also included in Table 3-2.

Table 3-2: Strategist Scenarios Analyzed Base Assumptions

	Partner Future	CWL Control Future
Scenario	**1**	**2**
Plan Year	RESOURCE (Capacity)	RESOURCE (Capacity)
2013		
2014		
2015		
2016		
2017	DEF(6)	DEF(6)
2018	DEF(13)	DEF(13)
2019	DEF(20)	RECIP BLOCK(9) RECIP ENGINE(9) DEF(2)
2020	DEF(28)	RECIP ENGINE(9) DEF(1)
2021	DEF(36)	RECIP ENGINE(9)
2022	1x1 7FA CCGT 25%(95)	DEF(7)
2023		RECIP ENGINE(9) DEF(6)
2024		DEF(15)
2025		DEF(23)
2026		DEF(30)
2027		DEF(39)
2028		DEF(48)
2029	DEF(5)	DEF(55)
2030	DEF(13)	DEF(63)
NPV UTILITY COST (@ 4.0%) PLANNING PERIOD ($000) *% DIFFERENCE (FROM LOWEST COST)*	$1,604,241 *0.00%*	$1,626,830 *1.41%*

Note: DEF(MW) indicates capacity purchases from the MISO market to cover the capacity deficit for that year.

The deficient DEF capacity in the portfolios is obtained from the market until it is determined that a resource is more economical. As seen in the above table, the lower cost portfolio shows the combined cycle capacity (95MW) being added in 2020. Although the portfolio with the combined cycle unit is the lower evaluated future, CWL would require the identification of a partner in order to have access to this type of resource. The portfolios which include the reciprocating engines are only slightly above the one with the combined cycle resource. CWL could develop the reciprocating engine capacity on its own. Therefore, the results provide a boundary between a future where CWL works with a partner to develop a joint owned resource or develops its own resources.

Another consideration in the resource futures is the timing of when a decision would be needed to commit to a resource strategy. In the partner future, CWL would likely have to commit early in the development process in order to be fully engaged in a project whose likelihood of success would require early, full commitment by the partners. The development process for a large combined cycle unit would entail major activities of site selection, interconnection application with the RTO and transmission owner, permitting, engineering, partner agreements and commitments, financing, pipeline infrastructure development, and construction. A typical estimate of the schedule for these activities would be four to five years from selection of a partner. During this process, CWL would be a minority participant in the project. This schedule assumes an aggressive approach to developing the resources.

The schedule for the partner future would be compared to the addition of CWL constructed resources. Since this future would be under CWL control, the early development issues associated with looking for a partner, a project, etc would be eliminated. Major tasks would include site selection and infrastructure development, permitting, engineering and construction. The process of developing an engine plant includes developing the building, switchyard, balance of plant and other infrastructure to allow for easy installation of future units. This tend to put more effort and per unit cost into the first installation, with subsequent units sharing the up-front costs as they are installed. Schedules for the development of a reciprocating engine plant would be about three years for the first installation and then approximately eighteen months for the subsequent units.

Although the reciprocating engines were used in the Strategist comparison of the futures, the use of the CEC combined cycle expansion would also provide similar economics, based on the assumptions used herein. Within the scope of this 2013 Update, it was not possible to perform detailed analysis of the expansion of the CEC facility into a combined cycle operation. However, Burns & McDonnell has developed several repowering analyses and applied this experience to develop the assumptions regarding the CEC expansion. Although it appears technically feasible with potential economics comparable to the reciprocating engines, there are important issues that need to be considered for this conversion.

The first is the ability to change the permit for the facility without incurring substantial cost in modifying the site. The existing CEC permit, as understood by Burns & McDonnell allows 400 hours of operation in the summer season. Capacity factors for the engines in the Strategist analysis range from approximately 40 to 50 percent. It is expected the combined cycle units would operate in a similar range or over 4,000 hours per year.

The second issue involves the dispatch of the facility into the MISO market as compared to the reciprocating engines. The average annual output of each CEC unit, when including the base combined cycle capacity, would be approximately 63MW. The efficiency of this capacity would be approximately the same as the reciprocating engine. However, the start time, minimum run time and impacts to O&M could be significantly different. The reciprocating engines can typically be in and out of the market on an hourly basis, which helps to improve the revenue margin on these facilities when compared to the smaller combined cycle units.

The third issue is the cost of installation. It is typically more expensive to retrofit an existing facility, especially when it was not designed for such a retrofit, than the development of a new plant. Although the cost estimates developed are suitable for purposes of this 2013 Update, more detailed engineering of both the reciprocating engine facility and the CEC combined cycle expansion are needed.

Understanding of the above issues for the CEC and the approach and costs to develop the alternative reciprocating engine plant would then be considered with regard to the value to the MISO market. This level of analysis would be required in order to determine which alternative would be the more attractive option. Should the operating and economic issues work out to be similar, it is a potential that both the CEC expansion and reciprocating engines could be used within the CWL resource portfolio over the study horizon.

3.6 RENEWABLE RESOURCES

CWL has been directed to maintain a certain percentage of renewable energy in its resource mix as described in Section 2. The current mix of renewable energy used by CWL includes biomass, wind, solar and landfill gas. Current negotiations are underway for the inclusion of additional biomass into this mix. For purposes of this analysis, Burns & McDonnell assumed that any renewable energy deficit would be made up with increased acquisition of wind energy. Wind capacity is accredited at approximately 15 percent of its nameplate rating. Therefore, as CWL increases its purchase of wind energy, it will have a minimal impact on the Strategist analysis and the portfolios selected.

3.6.1 Wind

The construction of new or expanded wind farms is driven primarily from the need for utilities to comply with renewable portfolio standards (RPS) and as settlement offers with environmental organizations. For purposes of this study, CWL is projected to add approximately 50MW of wind capacity over the next 20 years in order to comply with its RPS. This wind energy is assumed to be available in the quantities needed through new or amended power purchase agreements with wind energy producers, similar to the existing wind power purchase agreements.

3.6.2 Solar

CWL is one of the leaders in the Midwest with regards to the use of solar produced through photovoltaic options. The existing use of solar by CWL's customers has provided hourly output of solar energy from fixed arrays. The expanded installation of solar through the FreePower contract will increase the use of solar PV by CWL.

The economics of solar have typically been based on the average cost of power. The economics can be viewed from the utility's perspective with regards to the cost of solar compared to wholesale pricing. Since solar PV can be used by the customer in net metering configurations, it can also be viewed by the customer with regards to solar costs compared to the retail rates. The cost of solar PV has been declining. The projection of the point at which the cost of energy from solar will reach "parity" with the wholesale and retail pricing have seen the projected year coming sooner than previous projections. Figure 3-3 provides a current projection from the DOE.

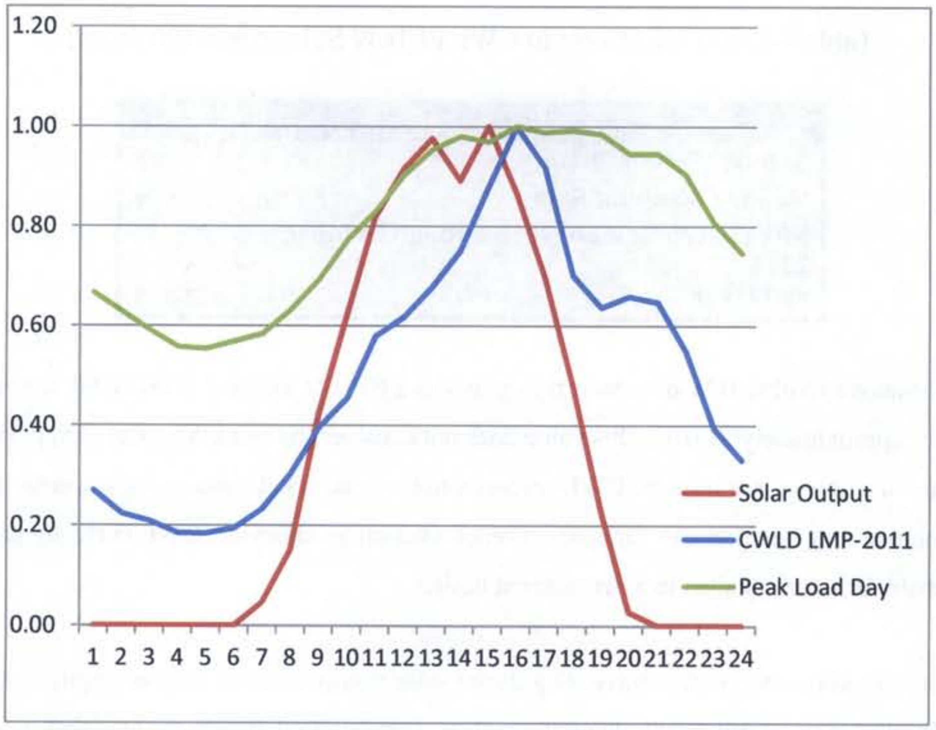
Figure 3-3: Projections of Solar PV Parity

Note: Graph shows the leveled cost of electricity for solar photovoltaics, which is the total capital and operating costs over the lifetime of the solar panels, divided by total electricity generated in kWh.[26]
Source: U.S. DOE Solar Energy Technologies Program.

As the price of solar decreases (and electricity rates increase at the retail level) the use of solar will increase in net metering applications. Utilities will need to be aware of the potential erosion of retail kWh sales and the impact this may have on the rates. For example, at the residential level rates usually include a customer charge and an average kWh charge. If the kWh rate includes fixed costs of the utility, the decline in retail sales due to the net metered solar will reduce the revenue collected to cover the fixed costs. This will require the utility to either adjust the customer charge or increase its average kWh charge.

Figure 3-4 provides a normalized comparison of a fixed solar array output (on the CWL system) as compared to the LMP of the CWLD.CWLD load node on July 20, 2011 and the CWL peak load in 2011. It can be seen that the alignment of the output of the solar array with the LMP and the CWL peak load indicates that the energy is available at times when the LMP market is not at its peak and for a short portion of the CWL peak load.

Figure 3-4: Fixed Solar Array Output in Columbia, Peak Load (2011) and CWLD LMP Pricing (Normalized)



The value of solar energy to the CWL system is to reduce the amount of energy that needs to be imported from the MISO market and the transmission losses associated with the delivery. The losses include those on the CWL distribution system. Burns & McDonnell developed an analysis of the expected value of solar energy to CWL. The analysis compared the hourly output from the solar PV array provided by CWL to the corresponding day ahead LMP at the CWL MISO load node.

The avoided cost to CWL would be the hourly LMP times the output from the solar array. The hourly LMPs from October 2011 through September 2012 at the CWL load node were used. These LMPs were multiplied by the hourly output from the solar information provided by CWL to create the avoided cost. These hourly avoided costs were summed across each month to create the total avoided costs by month. The hourly LMPs in the MISO market for the hours where solar energy is available are established primarily by the cost of natural gas. Any escalation in the natural gas price directly affects the LMPs during these hours. Therefore, the monthly avoided costs were escalated at the monthly forecast for natural gas used in the supply side analysis above.

A net present value using a 4 percent discount rate was created from the monthly avoided costs over a twenty year period. The twenty year period was chosen due to the expected life of the solar panels. The costs were normalized to a 1kW AC output array. Table 3-3 shows the results of the analysis on a 1kW basis.

Table 3-3: Avoided Costs to CWL of 1kW Solar Array (20 years)

Annual Discount Rate	4%
Monthly Discount Rate	0.33%
NPV ($/kWh)October 2013 through October 2033	$1,073.12
kWh/Year	1462.51

As seen in the above results, 1kW of solar arrays provides a NPV of avoided MISO LMP cost over a 20-year period of approximately $1,070. This value does not consider the lost kWh sales of approximately 1,462kWh and the impact that it has to CWL revenues to cover its fixed costs or any expenses associated with metering that may be necessary for connection of a net metered device. CWL currently provides a $500/kW rebate for solar installed in a net metered basis.

As solar energy reaches retail parity, increasing use of solar energy in a net metered application will occur. The level of solar energy currently on the system is so small relative to the load that it does not show as influencing the load shape of CWL. As the use of net metered solar systems increase, CWL will see an increasing early morning load that peaks and then declines as the solar energy output increases during the day. As the solar energy then begins to decrease in the afternoon, the load will then have a second afternoon peak. Assuming that the CWL customers are not the only ones taking advantage of the solar parity issue at the net metered level, the entire MISO load will be affected in a similar fashion.

Figure 3-5 is a graph of market energy prices in Germany in the summer of 2012. Germany has had an aggressive feed in tariff for solar and now has solar resources installed equal to approximately 30 percent of its demand. As seen, the market pricing peaks in the morning and afternoon with a deep valley during the day. This is a proxy for how the load is varying during the day. From a utility perspective, net metered solar resources will be a significant demand reduction (and the resulting energy) program. Unlike wind energy which is typically not being produced during hot peak times, solar is almost assured to be producing heavily during this time.

Figure 3-5: German Wholesale Electricity Prices July 2012

Another facet of the introduction of significant amounts of solar into the system will be a shifting of energy use to take maximum advantage of the energy produced. This could foster the use of retail level thermal storage devices to store the abundant solar energy during the day and use it during the afternoon period when the peak occurs slightly after the peak in solar energy production. This would cause a shift in the load and the resulting market pricing.

As the addition of solar energy expands, it will have a disrupting impact on the wholesale market during on peak hours as wind has had during off peak hours. An issue with solar is that its installation will most likely be behind the meter and create significant reductions in retail energy sales. This could lead to significant impacts to the retail rates as well as wholesale rates.

Another impact of a heavy use of solar will be to impact the revenues to owners of large coal and nuclear facilities. These assets have already been significantly impacted at the wholesale level by wind during heavy wind output periods. The revenues obtained during the peak hours of the market have been declining since 2008 but still provide a large portion of the overall revenues for the facilities. When peak period pricing begins to be impacted by solar energy, then the value of these assets will decline further. Resources that can move quickly in and out of the market will be the more attractive assets. As it turns out, these types of assets are the resources fired on natural gas that are identified in the Strategist portfolios above, especially the reciprocating engines. Also, CWL should need less capacity from traditional resources as the use of solar energy increases on the CWL system and the net peak to the MISO market is impacted.

* * * * *

SECTION 4.0

DEMAND SIDE ANALYSIS

4.0 DEMAND SIDE ANALYSIS

4.1 METHODOLOGY

Previous analyses for CWL with regard to Demand Side Management (DSM) programs have used "typical" data from other utilities. This data has been used where it was appropriate to reflect the expected results of potential DSM programs as developed by CWL. The scope of study for this 2013 Update was developed to move away from using data from outside sources and move towards the use of CWL specific data. Many of the most beneficial programs identified in the 2008 Study have been implemented by CWL. Several of these programs have been active since 2009. Certain aspects of the programs have been active for much longer. The actual results of the programs are used where possible.

The analysis of demand side management potential for a utility requires a significant amount of customer data to be mined that includes, but is not limited to:

- The number of existing end-use applications specific to the utility customer base and pertinent information (for example the number of central air conditioners broken down by age, efficiency rating and size)
- The demand and energy impacts to the utility of moving to higher efficiency applications of each of the end uses on the system
- The cost of moving to these higher efficiency applications
- The pace at which the existing appliances could be replaced with higher efficiency options
- The benefit of investing in these applications as compared to other approaches to meeting the customer service required

The development of a DSM analysis includes the following major tasks:

1. Determining the number of end use devices available for consideration
2. Establishing estimates for the number of potential and achievable participants in programs
3. Estimating the average reduction per participant
4. Estimating the demand and energy impact of the programs
5. Identifying the cost of the program
6. Developing the benefit cost ratio of the programs
7. Determining the expected impact on the supply side requirements

This section of the report discusses the development of the above major tasks.

The programs in active use by CWL are described in annual reports prepared by CWL for the city council. The most recent report provided to Burns & McDonnell was the *Demand Side Management and Demand Response Report,* March 2012, which summarized the DSM program results to 2011. Additional commercial information on DSM programs was provided for 2012.

4.2 2008 IRP DEMAND SIDE ANALYSIS

A detailed DSM study was performed for the 2008 IRP. Numerous DSM efficiency measures were evaluated for residential, commercial and industrial customers. The residential DSM assessment included an evaluation of a variety of different load management and conservation programs that were directed at reducing the overall peak demand and energy consumption of CWL residential customers. The assessment included programs by building stock, HVAC programs, thermal envelope programs, and appliance programs.

The intent of the commercial assessment was to give a reasonable estimate of the potential for commercial DSM efficiency measures with the existing building stock. Further analysis reviewed opportunities for improved building design and construction which can minimize future requirements. As with the residential assessment, programs by building stock, HVAC, thermal energy, and appliances were evaluated, along with lighting.

The evaluation of the DSM programs was performed through benefit/cost analysis. An initial screening of programs was made to determine those that fit the DSM objectives. The costs of the programs are then considered and compared to the benefits derived from the implementation using a benefit/cost analysis. Those programs with a benefit/cost ratio greater than one are then compared to supply side options to determine the most economic mix of demand and supply alternatives.

Based on the detailed DSM study performed in 2008, several DSM efficiency measures were put into place by CWL. Some of these programs are detailed below and used as the basis of the current DSM program evaluation.

4.3 DSM UPDATE ANALYSIS

The intent of analyzing DSM in this 2013 Update was to evaluate the costs and benefits of the programs currently being managed by CWL and compare these attributes to the changes in the supply side costs.

The interest of CWL was to determine if the existing programs were still beneficial and if DSM offerings should be expanded. This analysis of DSM evaluated the programs CWL currently has in place, using historical data for each of the programs to determine if CWL should continue each of the programs and the potential each program has on CWL's load forecast when considering current participation rates.

4.3.1 Residential Programs

The residential DSM assessment included an evaluation of the current programs in use by CWL. The programs detailed below are programs with measurable success. There are many other programs being implemented by CWL including load management and load shedding programs as well as educational programs.

4.3.1.1 Home Performance with Energy Star

This is a national program that brings existing homes up to Energy Star standards. After a detailed home assessment by a certified contractor is completed, electric customers can qualify for rebates and a loan for the suggested improvements. The incentives are based on the energy saved and the utility cost benefit. This single program implements most of the suggested Integrated Resource Plan residential efficiency measures and has resulted in a 0.479MW coincident peak reduction and a 2,500MWh savings since inception of the program.

4.3.1.2 Air Conditioner or Heat Pump Rebates

Air conditioner or heat pump incentives are based on the size of the system and the SEER (efficiency rating) of the system. The amount of the incentive is based on the amount of energy saved and the utility cost benefit. This program has high targeted energy savings due to cooling systems being one of the largest drivers of peak electric demand in the summer. This rebate program has a cumulative savings of 0.396MW and over 2,500MWh.

4.3.1.3 Energy Audits

The energy audits are free evaluations and provide energy and water efficiency tips specific to each customer. Energy savings are harder to calculate for this program since it is not as in-depth as the Home Performance with Energy Star assessment. There was an estimated savings of over 100,000 kilowatt hours in 2011 with a minimal expenditure since one staff person administers the program.

4.3.1.4 Tree Power

This program promotes energy conservation through energy efficient landscaping. Customers receive a landscape audit which indicates where they should plant their free 6- to 8- foot tall shade tree. Three properly placed shade trees, at maturity, can reduce cooling costs by 30 percent. The amount of new homes being built has been lower the last several years which has reduced participation since that is a targeted market.

4.3.1.5 Window Air Conditioner Exchange Program

To reduce summer electric bills for low-income customers that use window air conditioning units, an exchange program was started in 2007. An income qualified person brings in an older, inefficient unit and is given a new, Energy Star rated window unit provided by the utility. The average savings per unit is 730 kilowatt hours per year.

4.3.2 Commercial Programs

The commercial DSM assessment included an evaluation of the current programs in use by CWL. The programs detailed below are programs with measurable success.

4.3.2.1 Lighting Incentive Program

CWL encourages commercial customers to reduce their electric usage with a $300 per kilowatt reduction in their lighting systems. The last IRP identified lighting as the area where the most energy efficiency could be gained in the commercial sector. This program has provided the utility with more energy savings than any other program.

4.4 ACTIVE DSM PROGRAM PROJECTIONS

4.4.1 Residential and Commercial

The primary programs in the residential class affect the efficiency of the building enclosure and the HVAC systems. Considerations about these types of programs require an understanding of the number, age and building styles in the CWL service area and the age and efficiency of the HVAC systems. In discussions with CWL this end use survey information was reviewed in the context of available information from CWL.

CWL had the number and age of houses in the service territory, but was not tracking the number of homes in each age group that was participating in the Home Performance program. This information would be useful to determine the participation rates, demand and energy reductions and costs for upgrades by age of the home. Similar information about the HVAC systems is needed to allow an understanding of the number of older HVAC units that should be targeted for replacement with more efficient appliances. Similar granularity of data is needed for the commercial buildings.

In order to start using CWL specific information, the number of houses in certain age groups in the CWL area was categorized using information taken from the EIA 2009 Energy Consumption Survey. This survey provided information such as age of central and window air conditioning units by year of construction as well as number of energy audits performed on homes. This information was used to determine the participation rate by year of construction for several of the residential programs.

Burns & McDonnell developed a spreadsheet that allows each of the housing and appliance age groups to be analyzed for the residential programs. The commercial lighting and HVAC programs were also included. This spreadsheet will be a useful tool for CWL to populate with information as it is collected and develop more targeted results using CWL specific data. The analysis was developed to determine the projected participation level of each program and the overall energy and demand savings by program.

The housing stock by year of construction was provided by CWL. Using this information and data taken from the EIA 2009 Energy Consumption Survey, a participation rate by year of construction was projected for each DSM program. The overall participation rate by program is based on historical information provided by CWL, as well as the average kWh and kW reduction per installation. By multiplying the participation rate by year of construction to the number of houses in that category gives the projected number of houses each year participating in the program. This number is then multiplied by the average savings per installation to determine the total saving by program.

As this spreadsheet is populated with information more accurately depicting the conditions with the CWL housing stock and appliances, more precise information about the potential for DSM in the residential and commercial sectors can be created.

4.4.2 Industrial

Industrial DSM programs are not as structured as the residential and commercial sectors due to the wide variability of industries. CWL key account representatives are aware of opportunities to work with industries to improve their efficiency through targeted improvements in a specific area. The incentive that can be provided for these unique offerings can be developed using the avoided cost for demand and energy and the expected savings for the targeted application. The avoided cost is provided in the next section.

4.4.3 Program Results

The total demand and energy savings by program is shown below in Table 4-1. The table also provides the cost benefit of the programs. The benefits of the programs were valued using the net present value of the avoided demand and energy across the ten year period of 2012 to 2021 using the cost of demand and energy as determined in the supply side analysis discussed in Section 3. As seen, the benefits of the active programs are greater than the costs. The details of the analysis are included in Appendix C.

Table 4-1 Historical DSM Program Demand and Energy Savings

	Historial Participation and Demand/Energy Savings					Strategist Data				
	Historical Participation	Historical Participation Percentage	Total MW Reduction	Total MWh Reduction	Total Cost	$/MW $383,173.34	$/MWh $494.12			
						Avoided Demand Cost ($)	Avoided Energy Cost ($)	Total Avoided Cost ($)	Continue Program	Program Savings
RESIDENTIAL										
Home Performance with Energy Star										
2010	607	2.57%	0.173	570	$233,473	$66,289	$281,845	$348,134	yes	$114,661
2011	906	3.84%	0.245	843	$515,369	$93,877	$416,334	$510,211	no	($5,158)
Total	1,513	6.40%	0.418	1,413	$748,842	$160,166	$698,178	$858,345	yes	$109,503
Air Conditioner or Heat Pump Rebates										
2010	192	0.81%	0.112	289	$65,500	$42,915	$142,701	$185,617	yes	$120,117
2011	368	1.56%	0.133	564	$141,230	$50,962	$278,572	$329,534	yes	$188,304
Total	560	2.37%	0.245	853	$206,730	$93,877	$421,273	$515,150	yes	$308,420
Online Energy Audit										
2010	1,396	5.91%	0.000	377	$0	$0	$186,243	$186,243	yes	$186,243
2011	605	2.56%	0.000	163	$8,260	$0	$80,714	$80,714	yes	$72,454
Total	2,001	8.47%	0.000	540	$8,260	$0	$266,957	$266,957	yes	$258,697
Energy Audits										
2010	276	1.17%	0.000	317	$0	$0	$156,418	$156,418	yes	$156,418
2011	576	2.44%	0.000	105	$0	$0	$52,006	$52,006	yes	$52,006
Total	852	3.61%	0.000	422	$0	$0	$208,424	$208,424	yes	$208,424
Tree Power and Landscape Audit										
2010	98	0.41%	0.005	33	$7,840	$1,839	$16,477	$18,316	yes	$10,476
2011	98	0.41%	0.002	102	$7,400	$575	$50,442	$51,017	yes	$43,617
Total	196	0.83%	0.006	135	$15,240	$2,414	$66,919	$69,333	yes	$54,093
Window Air Conditioner Exchange Program										
2010	125	0.53%	0.063	91	$22,950	$23,948	$45,088	$69,037	yes	$46,087
2011	30	0.13%	0.000	22	$0	$0	$10,821	$10,821	yes	$10,821
Total	155	0.66%	0.063	113	$22,950	$23,948	$55,909	$79,858	yes	$56,908
Total Residential Prog	-84	-0.36%	0.732	3,476	$1,002,022	$280,406	$1,717,660	$1,998,066	yes	
	2,583	10.93%								
COMMERCIAL										
Lighting Incentive Program										
2010	11	0.17%	0.185	648	$23,809	$70,887	$320,188	$391,075	yes	$367,266
2011	50	0.79%	0.460	1,449	$127,407	$176,260	$715,923	$892,183	yes	$764,776
2012	68	1.08%	0.636	1,943	$161,181	$243,698	$960,036	$1,203,734	yes	$1,042,553
Total	129	2.04%	1.281	4,040	$312,397	$490,845	$1,996,147	$2,486,992	yes	$2,174,595
HVAC										
2012	13	0.21%	0.058	100	$282,350	$22,224	$49,643	$71,867	no	($210,483)
Total	13	0.21%	0.058	100	$282,350	$22,224	$49,643	$71,867	no	($210,483)
Total Commercial Programs			1.339	4,140	$594,747	$513,069	$2,045,789	$2,558,859	yes	$1,964,112
Total All Programs			2.071	7,617	$1,596,769	$793,475	$3,763,450	$4,556,925	yes	$2,960,156

[1] Contractor Incentives are not included in the table above. These costs are marketing costs creating market transformation.
The incentives will be diminished when the market for the service is mature and the data reporting is automatic.
Contractor incentives were $318,000 in FY2010 and $412,000 in FY2011.

A comparison was made to the actual results for two of the programs versus those projected in the 2008 Study. The two programs selected allowed the actual versus projected values to be compared due to the specificity of the targeted appliance of the program. The comparisons are shown in the following table.

Table 4-2
Comparison of Actual versus Estimated DSM Results for Selected Programs

	Average kW		Average MWh	
	2008 Study	Actual	2008 Study	Actual
Residential HVAC	0.95	0.44	0.67	1.522
Commercial Lighting	22.1	9.9	63.1	31.3

The results of the residential HVAC program indicate that the newer air conditioners are providing less of a peak reduction than estimated, but greater energy savings. For the Commercial Lighting program, the average demand and energy reductions are approximately half of the projected amounts. It should be noted that the average projected values are based on the average per building analyzed in the 2008 Study whereas the actual values may be on a customer basis. In any event, moving to actual reductions as seen by CWL for its programs allows a more definitive estimate of the expected benefits. These actual results are used in the projections in the following tables and figures.

The total projected energy savings by program is presented in Table 4-3. Figure 4-1 presents the energy forecast reduction by program assuming the participation levels obtained by CWL continue. The total demand savings by program is presented in Table 4-4. Figure 4-2 presents the demand forecast reduction by program.

Table 4-3 Projected Energy Savings by DSM Program

	2013 (MWh)	2014 (MWh)	2015 (MWh)	2016 (MWh)	2017 (MWh)	2018 (MWh)	2019 (MWh)	2020 (MWh)	2021 (MWh)	2022 (MWh)
Energy Savings										
Home Performace with Energy Star - R	496	992	1,488	1,983	2,479	2,975	3,471	3,967	4,463	4,959
Air Conditioner/Heat Pump Rebates - R	458	916	1,374	1,832	2,290	2,748	3,206	3,664	4,122	4,580
Online Energy Audit - R	198	396	594	792	990	1,188	1,386	1,584	1,782	1,980
Tree Power & Landscape Audit - R	66	132	199	265	331	397	464	530	596	662
Window Air Conditioner Exchange Program - R	63	126	189	251	314	377	440	503	566	629
Lighting Incentive Program - C	1,141	2,284	3,431	4,580	5,733	6,888	8,046	9,207	10,371	11,537
HVAC - C	292	585	878	1,172	1,467	1,763	2,059	2,356	2,654	2,953
Potential Energy Savings	2,714	5,431	8,152	10,877	13,605	16,337	19,072	21,811	24,554	27,300
Energy Savings from Current DSM Programs [1]	7,617	7,617	7,617	7,617	7,617	7,617	7,617	7,617	7,617	7,617
Total Potential Energy Savings	10,330	13,048	15,768	18,493	21,221	23,953	26,689	29,428	32,170	34,917

[1] Actual energy savings from FY 2010 and FY 2011.

Figure 4-1 Projected Energy Forecast Reduction by DSM Program

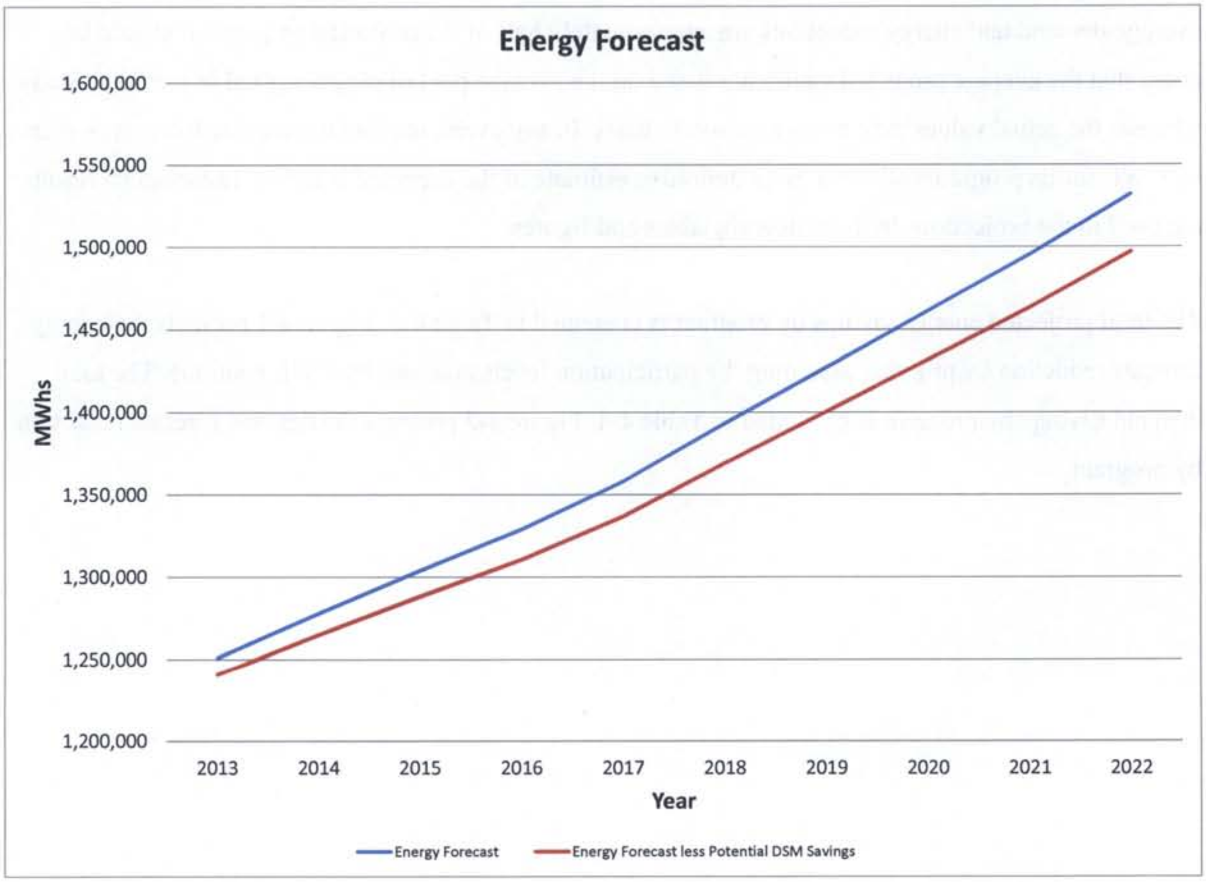
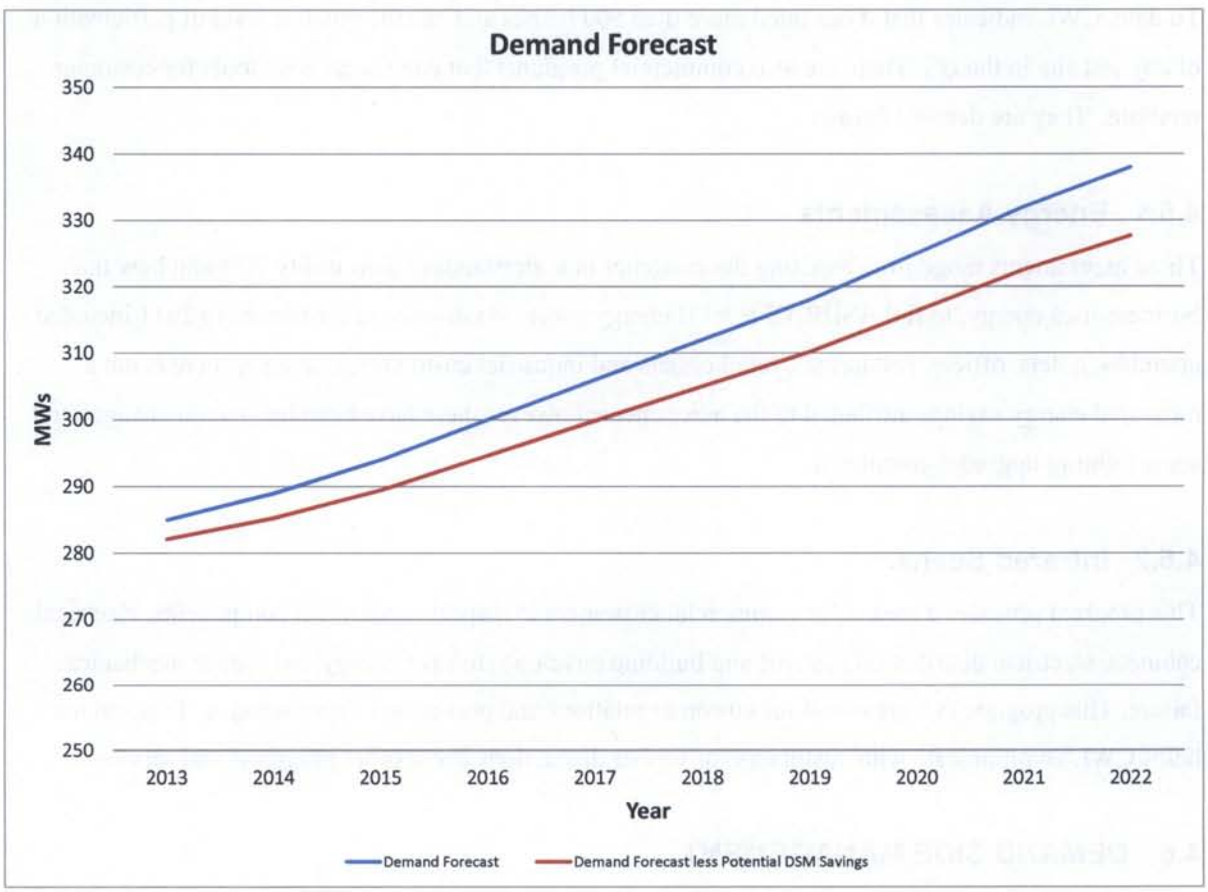


Table 4-4 Projected Demand Savings by DSM Program

	2013 (MW)	2014 (MW)	2015 (MW)	2016 (MW)	2017 (MW)	2018 (MW)	2019 (MW)	2020 (MW)	2021 (MW)	2022 (MW)
Demand Savings										
Home Performace with Energy Star - R	0.149	0.299	0.448	0.597	0.746	0.896	1.045	1.194	1.344	1.493
Air Conditioner/Heat Pump Rebates - R	0.133	0.265	0.398	0.530	0.663	0.796	0.928	1.061	1.193	1.326
Online Energy Audit - R	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Tree Power & Landscape Audit - R	0.003	0.007	0.010	0.013	0.017	0.020	0.023	0.026	0.030	0.033
Window Air Conditioner Exchange Program - R	0.034	0.069	0.103	0.138	0.172	0.207	0.241	0.276	0.310	0.344
Lighting Incentive Program - C	0.378	0.756	1.136	1.516	1.897	2.280	2.663	3.047	3.433	3.819
HVAC - C	0.123	0.247	0.371	0.496	0.620	0.745	0.870	0.996	1.122	1.248
Potential Demand Savings	0.821	1.643	2.466	3.290	4.116	4.943	5.771	6.601	7.431	8.263
Demand Savings from Current DSM Programs [1]	2.071	2.071	2.071	2.071	2.071	2.071	2.071	2.071	2.071	2.071
Total Potential Demand Savings	2.891	3.713	4.537	5.361	6.187	7.014	7.842	8.671	9.502	10.334

[1] Actual demand savings from FY 2010 and FY 2011.

Figure 4-2 Projected Demand Forecast Reduction by DSM Program



It should be noted that the rates for CWL are established considering an expectation of the amount of energy to be sold to end use customers. Most of the energy sold to CWL customers is priced on an average kWh basis and includes a certain amount of fixed costs. The effect of the efficiency programs is to reduce the energy sold on the CWL system. The revenue expected from these lost energy sales to recover the fixed cost assumed in the rate will have to be made up to maintain CWL's financial obligations.

4.5 PASSIVE DSM PROGRAMS

CWL is also engaged in a number of passive DSM programs. These programs are not measurable by energy or demand savings, but are very beneficial on a customer relations perspective. There are many educational, training and outreach programs in place. These range from conferences and expos to various school programs. CWL is a pilot community for the Department of Energy's Home Energy Score Program. This program allows homeowners to compare the energy performance of their homes to other homes nationwide. It also provides homeowners with suggestions for improving their homes' efficiency. To date, CWL indicates that it has rated more than 500 homes and has the greatest level of participation of any test site in the US. There are also commercial programs that have been great tools for customer relations. They are detailed below.

4.5.1 Energy Assessments

These assessments range from assisting the customer in understanding their utility bills and how their business uses energy, to full ASHRAE level II energy audits. Assistance to businesses in 2011 included churches, hotels, offices, restaurants, retail outlets and industrial customers. Currently there is not a measured energy savings attributed to the assessments however there have been behavioral changes and some lighting upgrades completed.

4.5.2 Infrared Scans

This program provides a means for commercial customers to inspect mechanical components, electrical cabinets, electrical distribution systems and building envelopes to save energy and reduce mechanical failure. This program is a great tool for customer relations and preventative maintenance. This service helps CWL communicate with customers for further discussions about other programs and services.

4.6 DEMAND SIDE MANAGEMENT

The most significant change in the look of DSM programs has been in the area of load control and the interruptible rate programs, now termed Demand Response. When these programs were first being implemented, they were used to reduce demand during a utility's peak. This reduction resulted in either a reduction of the demand used to determine the bill from its wholesale supplier or a reduction in the need for additional capacity for the utility.

One drawback to the DR programs for utilities using them to defer capacity is to determine the value of the reduction. Capacity additions tend to be "lumpy" when they are added. A utility that is deficient in capacity can rarely just add enough capacity to meet its load plus reserve obligation each year and no more. When utilities add capacity, they typically have more than needed for a few years then may go slightly deficit for a few years until the value of adding capacity is positive. During the deficit years, DR can assist in reducing the amount of capacity a utility has to buy. However, during the years when the utility is excess, the value of the load control for demand reduction purposes is minimal. This makes the value of the DR program vary over time.

For utilities such as CWL who are in a nodal market like MISO, the economic benefit to the DR programs is now achieved through slightly different metrics. Demand response can be bid into the market as capacity. This capacity can be used to meet the reserve obligations of the utilities or in the ancillary service market. The following table is from the FERC report "2011 Assessment of Demand Response and Advanced Metering".

Table 4-5 Demand Response Resource Potential at U.S. ISOs and RTOs

	2009 (MW)	Percent of 2009 Peak Demand[9]	2010 except as noted (MW)	Percent of 2010 Peak Demand[9]
California ISO	3,267[1]	7.1%	2,135[1]	4.5%
Electric Reliability Council of Texas	1,309[2]	2.1%	1,484[3]	2.3%
ISO New England, Inc.	2,183[2]	8.7%	2,116[4]	7.8%
Midwest Independent Transmission System Operator	5,300[2]	5.5%	8,663[5]	8.0%
New York Independent System Operator	3,291[2]	10.7%	2,498[6]	7.5%
PJM Interconnection, LLC	10,454[2]	7.2%	13,306[7]	10.5%
Southwest Power Pool, Inc.	1,385[2]	3.5%	1,500[8]	3.3%
Total RTO/ISO	27,189	6.1%	31,702	7.0%

Sources:
[1]California ISO 2010 Annual Report on Market Issues and Performance
[2]2010 FERC Survey
[3]ERCOT Quick Facts (June 2011)
[4]2010 Annual Markets Report, ISO New England Inc.
[5]2010 State of the Market report, Potomac Economics (Midwest ISO)
[6]2010 State of the Market report, Potomac Economics (New York ISO)
[7]PJM Load Response Activity Report, July 2011, "delivery year 2011-2012 active participants"
[8]Informational Status Report Concerning Incorporation of Demand Response In SPP Markets and Planning (September 2, 2011)
[9]Estimated based on peak demand data from the following: California ISO 2010 Annual Report on Market Issues and Performance, 2010 State of the Market Report for the ERCOT Wholesale Electricity Markets, 2010 Assessment of the Electricity Market in New England, 2010 State of the Market Report for the MISO Electricity Markets, New York ISO 2010 State of the Market Report, 2009 State of the Market Report for PJM and 2011 Quarterly State of the Market Report for PJM: January through June, and the Southwest Power Pool 2010 State of the Market.

Most markets require advanced metering in order to participate at the level reflected in the above table.

The value of capacity in the MISO market is at a very low level. Recent information provided by NERC indicates that the MISO market may have summer reserve margin levels in the range of 40 percent. This high level of reserves makes the value of capacity low. Therefore, the value of DR is also of low value for capacity. In addition to the benefits being low, the cost to manage a DR program that qualifies as bidding into the market may require the use of more expensive metering or other approaches to verifying the actual results as directed by the operators of the market.

An indication of how the DR market is changing is provided in the following from Smart Money magazine. New approaches to DR are targeting new types of incentives as more advanced metering is installed across the customer classes.

4.6.1 Utilities Using Reward Programs to Promote Efficiency

Utilities have embarked on programs to offer consumers loyalty points or cash in exchange for cutting their demand, Smart Money reported. The efforts were seen as a potential way to encourage consumers to accept smart meter rollouts, as consumers see greater benefits to using the meters to cut their demand. Bernard Neenan, a technical executive at the Electric Power Research Institute, told Smart Money that such perks "help utilities offset demand on the grid with an offer that's more enticing than the usual rebate programs for buying energy-efficient appliances." Wrote Smart Money: "Currently, 30 percent of U.S. households use smart meters, and 75 percent will by 2016, according to NPD In-Stat."

Southern California Edison, DTE Energy, Commonwealth Edison and Northeast Utilities were among the utilities that partnered with Efficiency 2.0, which used software to track year-on-year demand changes for a consumer and awarded points for lowering demand. Dominion offered cash payments to consumers in Virginia and North Carolina for having their air conditioners turned off as a demand response measure. Alternative supplier Energy Plus offered points for partner reward programs such as travel and hotel companies. *Smart Money, March 12.*

Another way DR can be used is to avoid high priced LMP energy. CWL purchases the majority of its energy from the MISO market at the nodal locational marginal price at its load node. The cost of this energy varies by hour in the day ahead and real time market. Table 4-6 provides an example of the hourly charges in the MISO day ahead market for the highest cost hour in 2012 ($187.89/MWh).

Table 4-6 LMP for CWL Node MISO

2012	HE 13	HE14	HE15	HE16	HE17	HE18	HE19
July 15	$41.03	$43.5	$45.21	$56.32	$59.71	$56.63	$45.27
July 16	$69.29	$84.37	$103.07	$121.39	$114.29	$87.06	$68.66
July 17	$100.01	$135.18	$163.63	$187.89	$153.26	$104.54	$80.00
July 18	$61.99	$75.94	$86.59	$95.79	$99.86	$67.74	$59.30

The new opportunity to value DR programs is to link them to the high price nodal hours. CWL currently has about 12MW of load under control when diversity is taken under consideration. Assuming for the sake of example, that 12MW could be taken off of the hours ending 15, 16 and 17 and returned over hours ending 18 and 19, an estimate of the LMP savings was calculated. The value of the reduced demand is shown in Table 4-7.

Table 4-7 Example LMP Savings due to Load Control

Hour	LMP ($/MWh)	Load change (MW)	Cost (Savings) per hour
HE 15	$163.63	-12	($1,963.56)
HE 16	$187.89	-12	($2,254.68)
HE 17	$153.26	-12	($1,839.12)
HE 18	$104.54	18	$1,881.72
HE 19	$80.00	18	$1,440.00
Total Savings			($2,735.64)

The example assumes that the MWh removed (3 h x12 MW =36MWh) are exactly replaced (2 h x 18 MW =36MWh). Information from CWL indicates that it takes approximately 29MW of controllable devices to obtain the 7.5MW of reduction for the residential load. The commercial and industrial customers provide the other 4.5MW. Assuming the savings would be distributed over the total participation of 33.5MW, the average savings for the above reductions would be approximately $81.67 per MW or approximately $0.08 per kW. Utilities need to make significant use of the load management during the year in order to pay for the installation of switches and overhead associated with the controls. The ability to pay customers in the form of monetary incentive to participate with the expected savings is limited.

Factors that could improve the benefits derived from a DR program include:

- Reserve margins declining due to capacity retirements and load growth
- Natural gas pricing escalating which increases the LMP
- Better ability to control load and remove more load during high priced LMP hours and manage pay back effects and costs to maximize return per MW.

Based on the above considerations, expansion of the current CWL demand response programs cannot support significant customer incentives. Utilities are, however, expanding their programs in the current environment. For instance, KCP&L is expanding their program by volunteers signing up for controllable thermostats. These programs are purely voluntary and no compensation is provided. Utilities that implement these programs indicate a 1 to 3 percent load reduction when activated. Due to the anticipated low MISO market pricing anticipated over the next several years until natural gas prices increase, CWL should consider "grandfathering" the existing participants in the DR programs with the intent to gradually realign incentives, if offered, closer to the benefits derived by CWL using the DR in the MISO market.

4.7 THE FUTURE OF DSM

There are several dynamics in the electric industry that can have an impact on the opportunities for a utility to influence its customers to reduce demand and increase energy efficiency on its system. Equally as interesting is the question of the ongoing need for a utility to engage in this influencing of its customers.

There are a number of factors influencing the opportunities and need. These include:

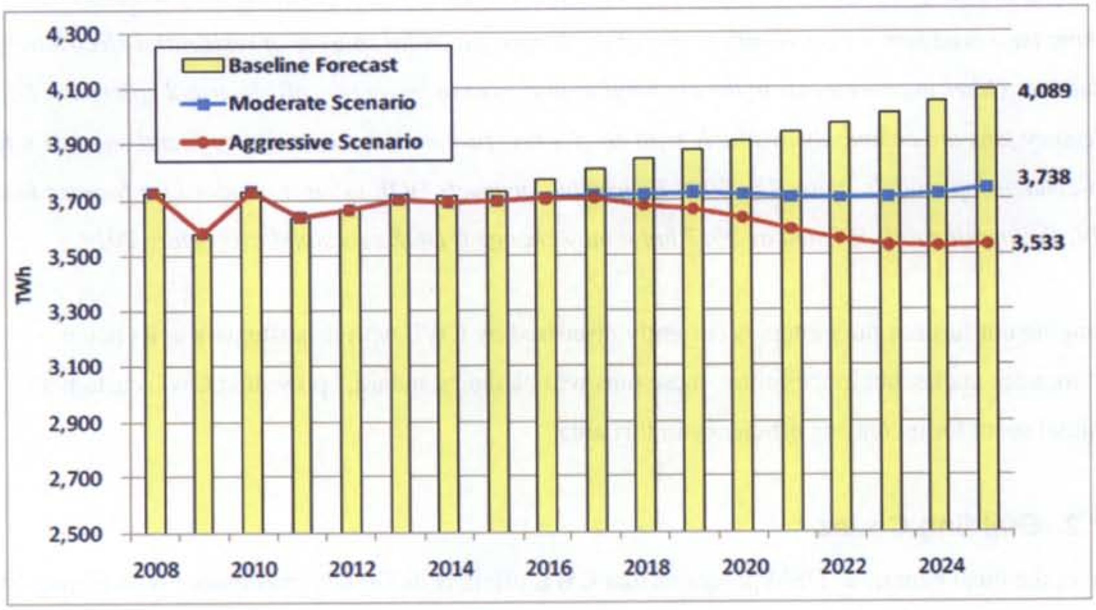
- A number of efficiency standards being promulgated by federal and state governments
- Acceptance of new home construction standards by builders and buyers
- The increasing real cost of electricity

The impact of these factors is for the utility to have a diminishing return on the ability to influence consumption on its system through more efficient use of electricity.

4.7.1 Appliance Standards

The impact of new appliance standards is significant. Estimates from the March 2012 report "The Efficiency Boom" prepared for the ACEEE & ASAP indicates that the standards currently in effect have reduced energy consumption by 7.5 percent from the projections without the standards. There are a significant number of new standards expected from the DOE over the next several years. These standards affect a large number of end use devices in the residential, commercial and industrial sectors. A summary of the standards and their expected dates can be found at http://www.appliance-standards.org. The graph shown in Figure 4-3 below is reproduced from "Assessment of Electricity Savings in the US Achievable through New Appliance/Equipment Efficiency Standards and Building Efficiency Codes (2010-2025), IEE, May 2011.

Figure 4-3 Estimated Savings from Future Efficiency Standards



The baseline forecast in the above figure reflects the impact of current standards. The opportunities a utility has to influence customers to higher efficiencies will diminish over time as the standards naturally migrate consumers to the more efficient products. These standards will have a large impact on the ability of CWL to change out low efficiency appliances to higher efficiency appliances over time.

An example of this is the impact of lighting standards. One of the most attractive DSM offerings utilities could offer was to get customers to switch out incandescent lighting out for compact fluorescents. New lighting standards are removing the incandescent bulbs from the market and it is no longer necessary for the utility to offer this type of program. Utilities were able to exchange a 60 to 75 Watt incandescent for a

12 to 15 Watt compact fluorescent, resulting in a significant reduction in consumption. Offering LED type bulbs only provides a Watt or two of reduction over a CFL, if that.

The impact of future standards will have a similar limiting effect. As an example of one potential standard, from the Appliance Savings Awareness Project website (link provided above): *Furnace fans are among the largest users of electricity in a typical household, consuming over 1,100 kWh of electricity per year on a national average basis, or more than 12% of the average U.S. household's electricity use. About 500 kWh of this total is consumed during the heating season and the remainder (600 kWh) is used to circulate cooled air in the summertime (ACEEE estimate). More efficient motor technologies, such as switching to energy-efficient BPM motors, can reduce fan electricity consumption by around 60%, making improved furnace air handlers one of the largest potential sources of residential electricity use reduction. Other improvements in the air handler may also improve overall electrical efficiency. High-efficiency fans are commonly available with condensing furnaces, but can also be found on quite a few non-condensing models. Note: The 2007 Energy bill instructs DOE to set a standard for furnace fans by 2014. Preemption date is listed as 2017 but it may change if DOE sets standards before 2014.*

Changing out furnace fan motors is currently discussed by CWL with its customers in its home performance audits, but in the future, these fans will be the "standard," providing CWL customers minimal room for increasing efficiency in this area.

4.7.2 Building Codes

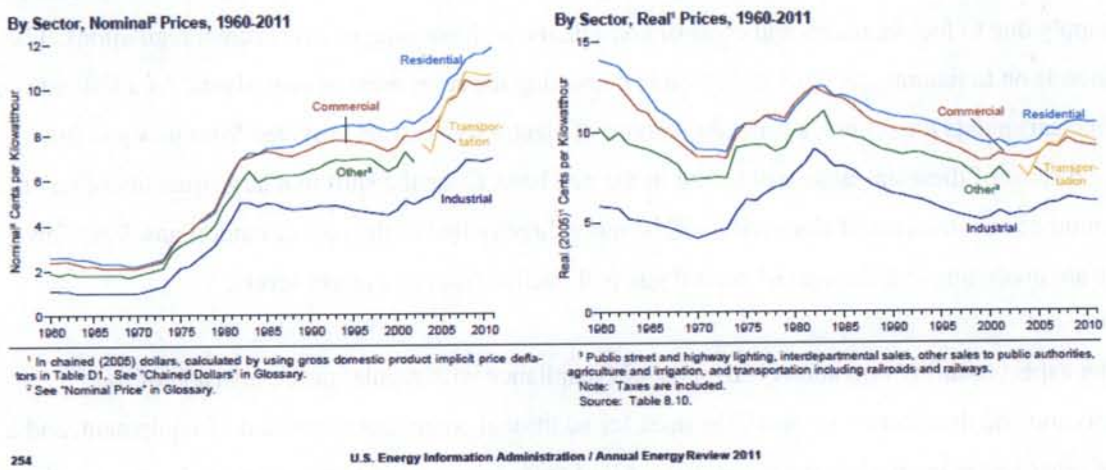
One of the most beneficial DSM programs that CWL offers is its Home Performance with Energy Star program for residential construction. This program works to improve the efficiency of existing residential homes to Energy Star levels. The EIA estimates that homes built to voluntary ENERGY STAR® specifications made up about 26 percent of all new homes constructed in the United States during 2011. Under the latest update of the specifications that went into effect earlier this year, ENERGY STAR homes consume at least 15 percent less energy than those built to the 2009 International Energy Conservation Code (IECC).

Based on the above, the adoption and enforcement of more stringent building codes can have a dramatic impact on the ability of a utility to reduce consumption by upgrading existing building stock. It should be apparent that it is not the responsibility of (nor does it makes sense for) a utility to invest its capital in dollars and personnel to bring poor building construction up to higher standards. Governing bodies should implement policies to bring all new construction up to the level desired by the community and enforce those policies. The incorporation of the efficiencies desired in the initial construction is much more cost effective than having the utility implementing them later. Once more stringent codes are implemented and enforced, CWL will have a declining stock of existing structures to work with for energy efficiency improvements as the existing buildings are upgraded.

4.7.3 Real Cost of Energy

Another issue affecting the need for a utility to entice customers to DSM programs is the rising cost of electricity. In times when the real cost of electricity is increasing, consumers look for ways to decrease their electricity bills. This naturally leads to more conservation by consumers. From the Annual Energy Review 2011, developed by the Energy Information Agency, Figure 4-4 shows the nominal and real prices of electricity since 1960.

Figure 4-4 Nominal and Real Electricity Prices



The concept of DSM started in the mid 70's. At this time, large amounts of coal and nuclear base load power plants were entering commercial operation. As the construction costs of these facilities were factored into utilities' ratebase, rates began to escalate significantly in both a nominal and real manner. The backlash against these rate increases forced regulated utilities to begin offering DSM programs in the 80's. Natural conservation began to occur and the rate of growth in the electric industry declined from its historical 7.5 percent rate of growth to approximately 2 percent.

The growth in electrical energy use allowed the cost of the baseload facilities to be spread over more kWh, which reduced rates. As seen in the above graphs, the nominal rate increased slightly, but the real cost of electricity declined significantly. Customers were less concerned about conservation, use of electronics expanded and the average of size of homes grew. Enticing customers to conserve during this type of economic climate required significant enticement.

The electric industry is now in a period of increasing nominal and real electricity prices. Due to the downturn in the economy and other factors, the growth of electricity is now projected by the EIA to be less than 1 percent, not including the potential impacts of more stringent efficiency standards in Figure 4-3. The increasing costs of electricity act to mitigate the cost differential of higher efficiency appliances as compared to lower efficiency options. This means that consumers will be selecting higher efficiency appliances more and probably sooner than they would if electricity costs were lower relative to their income.

Another issue to consider is that there are not substantial opportunities to decrease electricity rates. The cost of fuel represents the largest cost of electricity. The industry is currently seeing increasing costs of its coal supply due to fuel increases and costs of compliance with ongoing environmental regulations. The transition is on to natural gas. This transition is promoting the retirement of coal plants. As additional coal (and nuclear) plants are retired, a growing amount of electricity must be provided from new gas-fired units. The cost of these gas units will be put in the rate base. Once the shift to a large quantity of gas-fired generation occurs, the cost of electricity will be more directly tied to the cost of natural gas. Very few people are predicting that the cost of natural gas will decline from its current levels.

Another aspect to utility operations is the cost of compliance with regulations, expansion of the transmission and distribution systems, the need for additional communications and IT equipment, and a host of other issues increasing operating costs. All of these issues point to a continuing increase in the real cost of electricity and less of a need for a utility to entice customers to using electricity more efficiently.

4.7.4 Ongoing Utility DSM

It is expected that the new standards will be taking affect over the next 10 years. Ten years is approximately the life of most DSM programs. When considering participation rates of 2 to 5 percent per year, this time would provide for between 20 to 50 percent of the total potential of a program to be realized. It is expected that the remaining potential in a program would be achieved through natural migration to the higher efficiency through customer action independent of the utility. Therefore, it is expected that current DSM efforts will remain of benefit to CWL for approximately a 10 year horizon. If the implementation of the standards is delayed, then the DSM programs would be extended until the standards became effective.

4.8 DSM CONCLUSIONS

Based on the analysis of the existing DSM programs currently being managed by CWL, a revised cost benefit analysis using revised supply side assessments and the current conditions facing the utility industry, Burns & McDonnell offers the following conclusions:

1. With the exception of the commercial HVAC program, the existing active DSM programs being offered by CWL provide a positive benefit to cost ratio using the actual costs and performance of the programs and the updated supply side avoided costs.
2. The existing and anticipated efficiency standards that will affect the residential, commercial and industrial classes over the next 10 years will reduce the opportunities CWL has to gain reductions in demand and energy through its DSM efforts.
3. CWL should continue to improve its data collection regarding the inventory of residential and commercial structures and HVAC appliances in order to be targeting the locations that can provide the most benefit from its programs. As this information is collected, the spreadsheet provided with this report should be updated.
4. Due to the broad scope of the Home Performance audit and HVAC rebate program for residential, the targeting of the lighting and HVAC usage of commercial structures, and the anticipated efficiency standards, it does not appear that significantly expanding the DSM programs should be considered at this time.
5. The actual demand and energy savings provided by the DSM programs CWL is managing are below those estimated in the 2008 Study. CWL should explore approaches to increasing the participation rates in the CWL area.
6. The internet should be used to collect more targeted information about specific end use appliances to see if a targeted, limited life DSM program may be of benefit. For instance, collecting information about the number of homes with more than one refrigerator might provide information if initiating a one-time offer for turning in the second unit might be beneficial.
7. Due to the large rental housing market CWL has in its service area, information should be collected about the participation levels and success in this sector. The apartment energy density rating system is one way to engage this sector in DSM.
8. CWL should continue to discuss the approach to encouraging more efficient building codes and their enforcement in its service territory with the City. The movement towards Energy Star

performance for all new buildings would allow CWL to focus its efforts on improving the existing structures and eventually allow it to stop DSM programs aimed at retrofitting inefficient structures and make more efficient use of its capital and personnel.

9. CWL should consider its use of the demand response programs with regards to more active use in the MISO market. Consideration should be given to the incentives offered relative to the benefits. Expansion of the program should be considered to minimize the incentives required for participants.
10. As DSM benefits are obtained, the net effect will be to reduce the number of kWh sold by CWL. This may require a realignment of rates in order for CWL to maintain its revenues necessary to cover its fixed costs.

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SECTION 5.0

DSM AND SUPPLY SIDE CONSIDERATIONS

5.0 DSM AND SUPPLY SIDE CONSIDERATIONS

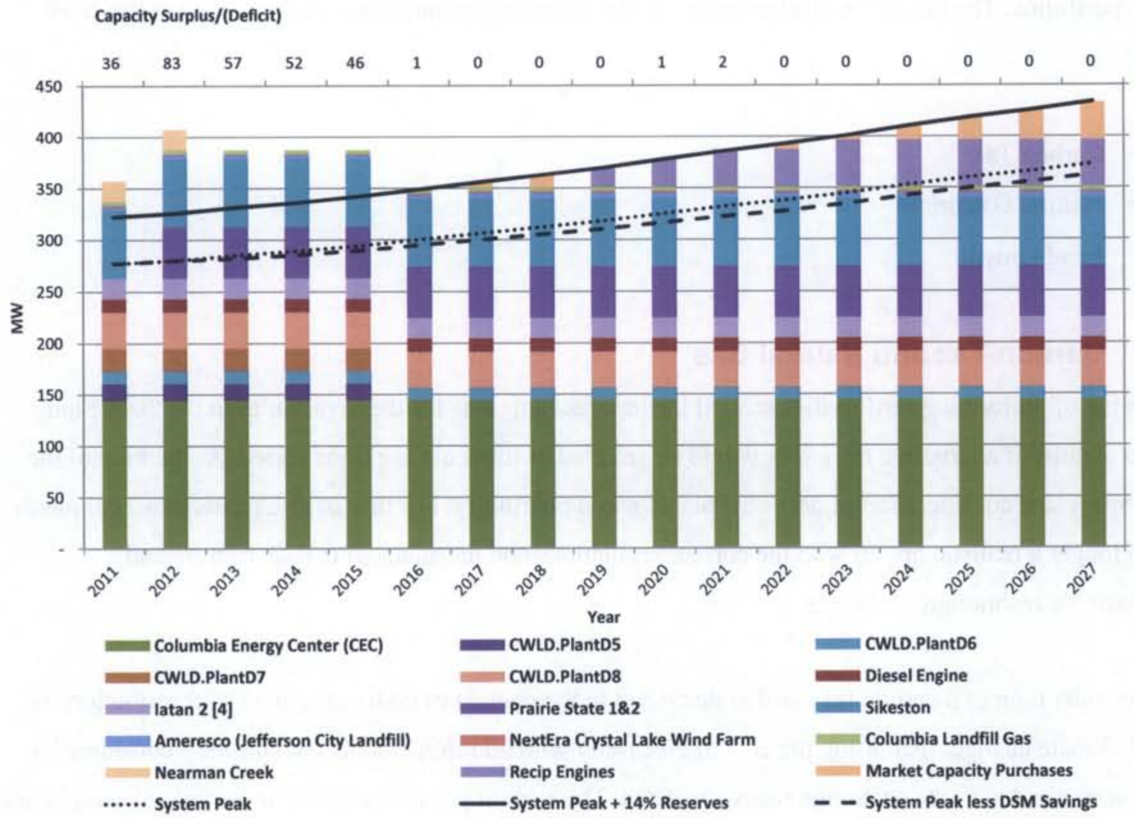
5.1 DSM IMPACTS ON SUPPLY SIDE DECISIONS

The future supply side opportunities to provide the necessary capacity required for CWL to meet its load plus reserve margin obligations are limited primarily to natural gas-fired resources. Should biomass fueled resources be acquired that would provide a net increase in capacity from that considered in Section 3, then additional capacity from the portfolios prepared in Section 3 would be reduced. Absent the additional biomass capacity, the renewable resources, other than the small capacity provided by landfill gas or wind accreditation, do not provide significant amounts of accredited capacity.

The natural gas fired resources available are essentially combustion turbines operating in either a simple or combined cycle mode and reciprocating engines. Based on the screening assessment, the combined cycle resource provided the lower overall costs. However, for CWL to obtain these economics, they would have to be a joint owner in a large facility developed by others. Due to the risk of the availability of the combined cycle resource, the portfolio with reciprocating engines, which CWL could construct on its own were considered as the likely portfolio to be realized. As discussed in Section 3, the conversion of the CEC to a combined cycle operation may also be an attractive option to replace a certain amount of the reciprocating engines.

The adjusted forecast due to expected impacts of the DSM programs reviewed in Section 4 currently being managed by CWL is shown on Figure 5-1. The figure also shows the portfolio under the future where CWL installs reciprocating engines to meet its power supply requirements. The engines have a rating of 9MW and can be installed one at a time. The impact of the DSM programs is to provide an opportunity to delay installation of capacity as compared to what would have been required without the DSM programs. If CWL is able to obtain more demand reductions than indicated, the opportunity may be created to delay additional capacity.

Figure 5-1 Balance of Loads and Resources with Expected DSM Impacts



In addition to the capacity impacts, CWL will be experiencing a shift in the sources of energy over time. Figure 2-2 shows the comparison of the sources of energy experienced by CWL in 2012 and projected for 2020. The amount of electrical energy provided by coal will decline over time, both in real quantities and percentage of total energy, as the incremental energy required by the market is provided by natural gas-fired facilities and renewable sources. The amount of renewable energy will grow based on the declining costs of its production and the increasing cost of electricity from fossil fired generation sources. This shift will assist in CWL reducing its emissions of carbon due to electricity production.

5.2 SENSITIVITIES

There are a variety of sensitivities that can be performed on the input assumptions for the selection of the above portfolios. The inclusion of adjustments to the following assumptions was provided in the 2008 Study:

- Carbon Tax
- Natural Gas prices
- Load Growth

5.2.1 Carbon Tax and Natural Gas

The value of performing sensitivities around the base assumptions for these variables in the 2008 Study was to identify if alternative resources would be selected as these assumptions varied. At the time of the 2008 Study, the consideration of new coal plants was a possibility. For this 2013 Update, new coal plants are no longer a realistic option with the current regulations and the status of carbon capture and sequestration technology and costs

The consideration of a carbon tax is often discussed in the context of addressing the US contributions to global climate change. Increasing the cost of electricity with additional tax is not currently considered a likely scenario due to the economic recovery status. The current political climate at the federal level is not conducive to a carbon tax being implemented soon. However, should a tax be levied, its effect would be to increase the cost of all energy produced by natural gas and coal.

The resource futures described herein are all based on new renewable and natural gas fired resources and continuing the DSM programs. Therefore, the impact of a carbon tax would not change the resource futures available to CWL, but would make the cost of all of the futures more expensive. A carbon tax would further the installation of wind and solar renewable energy by making the cost of that energy more attractive. CWL is also pursuing renewable energy from these sources and could increase its acquisition should a carbon tax be implemented.

With regard to natural gas, the forecast of natural gas used in this 2013 Update is based on an adjusted EIA forecast of natural gas. It is expected that there will be two issues that could potentially lead to a more rapid increase in the price of natural gas.

The first of these issues is the debate over whether to allow export of natural gas from the US. It is expected that if exports of liquefied natural gas are allowed, the price of domestic natural gas will increase towards its value on the world market. This could result in a two to three times increase in the price of natural gas.

The second potential impact could arise from the pressure from environmental regulations enacted to reduce the emissions of methane from the gas fields and the hydrological fracturing process. The costs of these regulations would be reflected in the price of the gas. Table 5-1 provides the results of increasing the natural gas forecast by 50 percent from the base forecast.

Table 5-1 NPV of Resource Futures with Gas Sensitivity

($000s)

	Partner	CWL Control	Diff
Base	$ 1,604,241	$ 1,626,830	$ 22,589
Gas Sensitivity	$ 1,687,432	$ 1,703,830	$ 16,398

When reviewing the options available to CWL, the inclusion of a carbon tax or higher forecast of natural gas prices would not change the selection of alternatives, since they are based on what CWL could potentially obtain to meet its capacity obligations due to its increasing load. The net effect would be to increase the overall cost of the futures, not change the selection.

5.2.2 Load Forecast Adjustments

The importance to reviewing the impact of looking at load on the forecast is to determine if it would have a material change in the supply side portfolio using the base forecast. Due to the ongoing efforts by CWL with DSM and the slow economic growth, it is not expected that a significant increase would occur in CWL's load forecast. If it did, it would simply advance the time when new resources would be needed and the amount. It would not change the technology selected.

If the load forecast decreased, then it would delay the time when resources are needed and potentially the amount. The load forecast has already declined from the base forecast used in the 2008 Study. Future decreases due to further efforts in the CWL DSM programs are projected above. As CWL works through its housing stock and customers move to more efficient appliances influenced by federal efficiency standards, the benefits from DSM will diminish.

The largest impact to load forecast could conceivably come from the ubiquitous appearance of solar PV at the net metered level. As discussed in Section 3, solar PV could reach retail parity within the next few years. Should a carbon tax be implemented or the price of natural gas suddenly increase, parity would be potentially be achieved more quickly and with a larger margin in favor of solar. The resulting impact on the CWL demand and energy requirements could be substantial as customers begin rapid acceptance of solar PV on a net metered basis. The solar market already includes 275 watt plug in solar PV packages that can be purchased, taken home and plugged into an outdoor outlet. It is expected that many homes would opt for larger installations.

CWL purchases essentially all of its energy from the MISO market. It sells energy from its generating resources into the MISO market. The revenues from the energy sales are used to offset the cost of the energy purchases. The increased use of net metered solar will reduce the amount of energy required to be purchased from the MISO market. As discussed in Section 3, natural gas-fired resources will be required to work with the wind and solar energy as the load curve becomes more variable. This will impact the revenues from the generation resources sold in to the MISO market. It is too early to begin predicting the dollar ramifications of the impacts of solar, but the potential trend is to reduce the load costs and change the revenues obtained from CWL generation resources.

5.3 CONCLUSIONS

Based on the analysis performed herein, Burns & McDonnell has developed the following conclusions.

1. CWL's base load forecast used in this 2013 Update is lower than the base forecast provided in the 2008 Study. The forecast includes the historical impacts of CWL DSM efforts.

2. Based on a review of CWL existing DSM programs and CWL's more attractive supply side expansion options, CWL should continue to pursue the existing DSM programs that it manages. The Commercial HVAC program should be reviewed to determine if its benefit can be increased.

3. CWL should continue to work with the City to improve the application and enforcement of more efficient building codes across the commercial and residential sectors. The current situation where CWL attempts to entice building owners to improve their building's efficiency through use of CWL incentives after they are constructed is not a good use of CWL capital or human resources.

4. Due to the number of existing and to be implemented federal efficiency standards and the rising cost of electricity, expansion into new DSM programs does not appear to be warranted. There are focused, short term programs that may be of use, such as second refrigerator turn-ins and targeted industrial offers that could have benefit. However, CWL DSM programs currently offer incentives in the higher value DSM areas.

5. CWL's supply side expansion options are essentially limited to natural gas fired and renewable energy resources. The need to add these resources, with the expected load forecasts, does not occur until approximately 2019. CWL should monitor the cost of capacity from the area market to determine if the actual construction of resources is more economical.

6. Should CWL determine that the CWL Controlled resource future is the course it desires to take, a detailed engineering analysis of the costs to expand the CEC to a combined cycle operation should be developed. Investigation into necessary permit modifications should also be made. This detailed evaluation should be compared to the value of the output of the facility to the MISO market and how it compares to the cost of the reciprocating engines.

7. The potential impact to the electric utility industry of solar PV achieving retail parity is significant. The timing of achieving this parity level could be within the next few years depending on the pricing of natural gas and general rate increases coming about due to the rising real cost of electricity. For CWL, a significant expansion of net metered solar PV would have a large impact on its MISO energy purchases, its sales from its generation and the capacity necessary to meet its load plus reserve obligations.

8. CWL should continue to review its rate structure to review the impact of declining sales from DSM and the potential impact due to increasing use of net metered solar PV.

9. An increase in the cost of wholesale electricity through a carbon tax or natural gas prices increasing will expand the value of DSM and net metered solar PV to CWL customers. It will not materially change the make-up of the lower cost supply side portfolio identified herein. If, however, CWL's load is materially affected by the large acceptance of net metered solar PV, then the lower cost portfolio would also change. It is expected that the need for additional natural gas fired resources would decline and be delayed.

* * * * *

APPENDIX A

STUDY ASSUMPTIONS

Assumptions for Production Cost Modeling

General Assumptions

- 25-year Net Present Value of incremental production expenses to serve native load
  - January 2013 to December 2037 study period
  - NPV in 2012 dollars
- Required capacity margin: 14 percent

Financial Assumptions

- Interest Rate: 4.0 percent
- Discount Rate: 4.0 percent
- General Inflation/O&M Escalation Rate: 3.5 percent

Demand and Energy Assumptions

	Demand (MW)	Energy (GWh)
2013	285	1,251
2014	289	1,278
2015	294	1,304
2016	300	1,329
2017	306	1,358
2018	312	1,393
2019	318	1,427
2020	325	1,461
2021	332	1,495
2022	338	1,532
2023	345	1,569
2024	353	1,607
2025	360	1,645
2026	366	1,663
2027	373	1,695
2028	381	1,727
2029	387	1,760
2030	394	1,792
2031	401	1,824
2032	408	1,857
2033	415	1,889
2034	422	1,921
2035	429	1,954
2036	436	1,986
2037	443	2,018

Market Forecast Assumptions

- ✓ One year historical hourly market prices covering the period from January 2010 – December 2010 based on Cinergy (Indiana) Hub
- ✓ Annual escalation follows the fuel forecast escalation used in this study. Off-peak prices follow coal escalations, on-peak prices follow natural gas escalations.
- ✓ Seasonal market prices entered in 2010$ as follows:

	On-Peak ($/MWh)	Off-Peak ($/MWh)
January	$47.31	$33.03
February	$43.68	$31.34
March	$36.02	$26.21
April	$35.35	$23.62
May	$39.05	$25.25
June	$49.54	$31.94
July	$54.66	$32.09
August	$52.22	$29.80
September	$36.98	$22.20
October	$32.98	$24.14
November	$35.33	$25.43
December	$44.76	$30.82

Emission Allowance Cost Assumptions

- ✓ Assumed cost per ton for emissions during study period
- ✓ Numbers based on EPA CSAPR presentation from December 2010

	SO2 ($/ton)	NOx Annual ($/ton)	NOx Ozone ($/ton)
2013	N/A	N/A	N/A
2014	$1,400	$763	$1,908
2015	$1,448	$790	$1,975
2016	$1,499	$818	$2,044
2017	$1,552	$846	$2,116
2018	$1,606	$876	$2,190
2019	$1,662	$907	$2,267
2020	$1,720	$938	$2,346
2021	$1,781	$971	$2,428
2022	$1,843	$1,005	$2,513
2023	$1,907	$1,040	$2,601
2024	$1,974	$1,077	$2,692
2025	$2,043	$1,114	$2,786
2026	$2,115	$1,154	$2,884
2027	$2,189	$1,194	$2,985
2028	$2,265	$1,236	$3,089
2029	$2,345	$1,279	$3,197
2030	$2,427	$1,324	$3,309
2031	$2,512	$1,370	$3,425

2032	$2,600	$1,418	$3,545
2033	$2,691	$1,468	$3,669
2034	$2,785	$1,519	$3,797
2035	$2,882	$1,572	$3,930
2036	$2,983	$1,627	$4,068
2037	$3,087	$1,684	$4,210

CWL Existing Resources

Combustion Turbines (Total Capacity of 156.5 MW):

Columbia Power Plant Unit 6:
- ✓ 12.5 MW capacity
- ✓ Associated fuel forecast – Natural Gas
- ✓ Heat rate 17,809 Btu/kWh
- ✓ Fixed O&M $121.27/kW-year, 2008$, escalated at inflation
- ✓ Variable O&M $43.67/MWh, 2008$, escalated at inflation

Modeled Emission Rates
NO_X: 0.2451 lbs/MMBtu
SO_2: 0.00053 lbs/MMBtu
CO_2: 119 lbs/MMBtu
Hg: N/A

Columbia Energy Center:
- ✓ 144.0 MW capacity
- ✓ Associated fuel forecast – Natural Gas
- ✓ Heat rate 12,793 Btu/kWh
- ✓ Fixed O&M $73.01/kW-year, 2008$, escalated at inflation
- ✓ Variable O&M $1.74/MWh, 2008$, escalated at inflation

Modeled Emission Rates
NO_X: 0.039 lbs/MMBtu
SO_2: N/A
CO_2: 118.75 lbs/MMBtu
Hg: N/A

Diesels (Total Capacity of 12.5 MW):

Distributed Generation:
- ✓ 12.5 MW capacity
- ✓ Associated fuel forecast – Distillate Fuel Oil
- ✓ Heat rate 8,961 Btu/kWh
- ✓ Fixed O&M Included in VOM
- ✓ Variable O&M $192.95/MWh, 2008$, escalated at inflation

Modeled Emission Rates

NO_X: N/A
SO_2: N/A
CO_2: N/A
Hg: N/A

Baseload and Intermediate Facilities (Total Capacity of 73.5 MW):

<u>Columbia Power Plant Unit 5:</u>
- ✓ 16.5 MW capacity
- ✓ Associated fuel forecast – Columbia Coal
- ✓ Heat rate 15,941 Btu/kWh
- ✓ Fixed O&M $68.90/kW-year, 2008$, escalated at inflation
- ✓ Variable O&M $26.52/MWh, 2008$, escalated at inflation
- ✓ O&M costs and emissions rates assumed to be same as Unit 7

Modeled Emission Rates
NO_X: 0.529 lbs/MMBtu
SO_2: 1.428 lbs/MMBtu
CO_2: 205 lbs/MMBtu
Hg: 8.488 lbs/TBtu

<u>Columbia Power Plant Unit 7:</u>
- ✓ 22.0 MW capacity
- ✓ Associated fuel forecast – Columbia Coal
- ✓ Heat rate 15,523 Btu/kWh
- ✓ Fixed O&M $68.90/kW-year, 2008$, escalated at inflation
- ✓ Variable O&M $26.52/MWh, 2008$, escalated at inflation

Modeled Emission Rates
NO_X: 0.529 lbs/MMBtu
SO_2: 1.428 lbs/MMBtu
CO_2: 205 lbs/MMBtu
Hg: 8.488 lbs/TBtu

<u>Columbia Power Plant Unit 8:</u>
- ✓ 35.0 MW capacity
- ✓ Associated fuel forecast – Natural Gas
- ✓ Heat rate 13,900 Btu/kWh
- ✓ Fixed O&M $10.80/kW-year, 2008$, escalated at inflation
- ✓ Variable O&M $0.94/MWh, 2008$, escalated at inflation

Modeled Emission Rates
NO_X: 0.529 lbs/MMBtu
SO_2: 1.925 lbs/MMBtu
CO_2: 205 lbs/MMBtu
Hg: 8.488 lbs/TBtu

Power Purchase Agreements (Total Capacity Varies Over Study Period):

Sikeston:

- ✓ 66.0 MW of coal-fired capacity
- ✓ Associated fuel forecast – N/A (fuel cost included in VOM)
- ✓ Heat rate 10,120 Btu/kWh
- ✓ Fixed O&M $204.96/kW-year, 2013$, escalated based on contract terms
- ✓ Variable O&M $24.28/MWh, 2013$, escalated based on contract terms

Modeled Emission Rates
NO_X: 0.22 lbs/MMBtu
SO_2: 0.6 lbs/MMBtu
CO_2: 212 lbs/MMBtu
Hg: 4.282 lbs/TBtu

Iatan 2:

- ✓ 20.0 MW of coal-fired capacity
- ✓ Associated fuel forecast – N/A (fuel cost included in VOM)
- ✓ Heat rate 9,200 Btu/kWh
- ✓ Fixed O&M $252.50/kW-year, 2013$, escalated based on contract terms
- ✓ Variable O&M $17.12/MWh, 2013$, escalated based on contract terms

Modeled Emission Rates
NO_X: 0.08 lbs/MMBtu
SO_2: 0.09 lbs/MMBtu
CO_2: 290 lbs/MMBtu
Hg: 0.045 lbs/TBtu

Prairie State:

- ✓ 50.0 MW of coal-fired capacity
- ✓ Associated fuel forecast – N/A (fuel cost included in VOM)
- ✓ Heat rate 9,400 Btu/kWh
- ✓ Fixed O&M $372.00/kW-year, 2013$, escalated based on contract terms
- ✓ Variable O&M $13.20/MWh, 2013$, escalated based on contract terms

Modeled Emission Rates
NO_X: 0.07 lbs/MMBtu
SO_2: 0.182 lbs/MMBtu
CO_2: 356 lbs/MMBtu
Hg: 2.013 lbs/TBtu

Blue Grass Ridge Wind Farm:

- ✓ 6.3 MW of aggregate wind power (14.7% firm capacity)
- ✓ Associated fuel forecast – N/A
- ✓ Heat rate N/A
- ✓ Fixed O&M $0.00/kW-year, 2013$, no escalation
- ✓ Variable O&M $65.00/MWh, 2013$, no escalation

Modeled Emission Rates
NO_X: N/A
SO_2: N/A
CO_2: N/A
Hg: N/A

NextEra Crystal Lake 3 Wind Farm:

- ✓ 10.5 MW of aggregate wind power (14.7% firm capacity)
- ✓ Associated fuel forecast – N/A
- ✓ Heat rate N/A
- ✓ Fixed O&M $0.00/kW-year, 2013$, no escalation
- ✓ Variable O&M $43.50/MWh, 2013$, escalates $1.00/year until it reaches $45.00, then no escalation

Modeled Emission Rates
NO_X: N/A
SO_2: N/A
CO_2: N/A
Hg: N/A

Ameresco and Columbia Landfill Gas:

- ✓ 7.2 MW of contract capacity
- ✓ Energy provided at ~90% capacity factor annually
- ✓ Associated fuel forecast – N/A
- ✓ Heat rate N/A
- ✓ Fixed O&M $0.00/kW-year, 2013$, no escalation
- ✓ Variable O&M $60.00/MWh, 2013$, no escalation

Modeled Emission Rates
NO_X: 0.428 lbs/MMBtu
SO_2: 0.772 lbs/MMBtu
CO_2: 205 lbs/MMBtu
Hg: 3.333 lbs/TBtu

CWL Supply Alternatives

Combined Cycle Gas Turbine (1x1 7FA CCGT):

- ✓ 25% CWL ownership
- ✓ 381.5 MW combined cycle facility at a greenfield location
  - ✓ 289.8 MW base load capacity with 91.7 MW of duct fired capacity
- ✓ Earliest commercial operation 2016
- ✓ Capital cost $1,160/kW, 2016$, escalated at inflation
- ✓ Associated fuel forecast – Natural Gas
- ✓ Heat rate 7,201 Btu/kWh
- ✓ Fixed O&M $11.39/kW-year, 2012$, escalated at inflation
- ✓ Variable O&M $2.60/MWh, 2012$, escalated at inflation

Modeled Emission Rates

NO_X: 0.009 lbs/MMBtu
SO_2: N/A
CO_2: 120 lbs/MMBtu
CO: 0.006 lbs/MMBtu
Hg: N/A

<u>Reciprocating Engines Block (Wartsila 20V34SG):</u>

- ✓ One 9.1 MW Wartsila engine with build out for six engines at a greenfield location
- ✓ Earliest commercial operation 2015
- ✓ Capital cost $4,310/kW, 2015$, escalated at inflation
- ✓ Associated fuel forecast – Natural Gas
- ✓ Heat rate 8,780 Btu/kWh
- ✓ Fixed O&M $32.00/kW-year, 2012$, escalated at inflation
- ✓ Variable O&M $6.10/MWh, 2012$, escalated at inflation

Modeled Emission Rates
NO_X: 0.018 lbs/MMBtu
SO_2: N/A
CO_2: 120 lbs/MMBtu
CO: 0.034 lbs/MMBtu
Hg: N/A

<u>Reciprocating Engine Add-On (Wartsila 20V34SG):</u>

- ✓ 9.1 MW Wartsila engine
- ✓ Earliest commercial operation 2015
- ✓ Capital cost $1,310/kW, 2015$, escalated at inflation
- ✓ Associated fuel forecast – Natural Gas
- ✓ Heat rate 8,780 Btu/kWh
- ✓ Fixed O&M $13.00/kW-year, 2012$, escalated at inflation
- ✓ Variable O&M $6.10/MWh, 2012$, escalated at inflation

Modeled Emission Rates
NO_X: 0.018 lbs/MMBtu
SO_2: N/A
CO_2: 120 lbs/MMBtu
CO: 0.034 lbs/MMBtu
Hg: N/A

<u>Market Capacity:</u>

- ✓ Up to 100 MW of capacity for reserve requirement needs
- ✓ Commercial operation 2013-2037, 1 year contracts
- ✓ Associated fuel forecast – N/A
- ✓ Heat rate N/A
- ✓ Fixed O&M $6.00/kW-year, 2013$, escalated $6.00/year until it reaches $30.00, then escalated at inflation
- ✓ Variable O&M $0.00/MWh, 2013$, no escalation

Modeled Emission Rates
NO_X: N/A
SO_2: N/A
CO_2: N/A
Hg: N/A

Power Purchase Agreement:
- ✓ 20 MW capacity
- ✓ Hourly dispatch range 50-100%
- ✓ Monthly capacity factor 80-90%
- ✓ Annual capacity factor 82-85%
- ✓ Contract terms June, 1 2014 to May 31, 2034
- ✓ Associated fuel forecast – N/A
- ✓ Heat rate N/A
- ✓ Fixed O&M $0.00/kW-year, 2014$, no escalation
- ✓ Variable O&M $43.55/MWh, 2014$, escalated based on contract terms

Fuel Forecasts

- ✓ Natural Gas forecast based on Early Release 2012 EIA Forecast for Delivered Natural Gas Prices to Henry Hub for Electric Power, then modified to include estimated Panhandle Eastern pipeline charges for delivery to Columbia
  - ✓ Average annual natural gas prices shown below, model uses a monthly scalar for gas
- ✓ Coal forecast based on Early Release 2012 EIA Forecast, Delivered Prices for Electric Power
  - ✓ Columbia Coal assumed to be twice as expensive as the Coal forecast
  - ✓ Prairie State Coal assumed to be $0.89 in 2012, escalated at inflation
- ✓ Fuel Oil price assumed to be $21.53/MMBtu in 2008, this price was escalated 3.5% per year to generate the forecast

	Natural Gas ($/MMBtu)	Coal ($/MMBtu)	Columbia Coal ($/MMBtu)	Prairie State Coal ($/MMBtu)	Fuel Oil ($/MMBtu)
2013	$4.72	$2.46	$4.92	$0.92	$25.57
2014	$4.84	$2.51	$5.02	$0.95	$26.47
2015	$5.05	$2.54	$5.08	$0.99	$27.39
2016	$5.17	$2.59	$5.18	$1.02	$28.35
2017	$5.41	$2.70	$5.40	$1.06	$29.34
2018	$5.70	$2.77	$5.54	$1.09	$30.37
2019	$5.97	$2.84	$5.68	$1.13	$31.43
2020	$6.18	$2.93	$5.86	$1.17	$32.53
2021	$6.55	$3.01	$6.02	$1.21	$33.67
2022	$7.05	$3.11	$6.22	$1.26	$34.85
2023	$7.44	$3.19	$6.38	$1.30	$36.07
2024	$7.79	$3.28	$6.56	$1.34	$37.33
2025	$8.10	$3.37	$6.74	$1.39	$38.64

2026	$8.57	$3.48	$6.96	$1.44	$39.99
2027	$9.00	$3.59	$7.18	$1.49	$41.39
2028	$9.18	$3.70	$7.40	$1.54	$42.84
2029	$9.28	$3.80	$7.60	$1.60	$44.34
2030	$9.55	$3.92	$7.84	$1.65	$45.89
2031	$10.07	$4.02	$8.04	$1.71	$47.50
2032	$10.65	$4.13	$8.26	$1.77	$49.16
2033	$11.08	$4.25	$8.50	$1.83	$50.88
2034	$11.54	$4.37	$8.74	$1.90	$52.66
2035	$12.13	$4.49	$8.98	$1.96	$54.50
2036	$12.55	$4.65	$9.29	$2.03	$56.41
2037	$12.99	$4.81	$9.62	$2.10	$58.39

APPENDIX B

SELECTED STRATEGIST SUPPLY SIDE ANALYSIS

Table B-1 Partner Future Base
Columbia Water and Light
Burns & McDonnell Project No. 67546
2012 IRP

Resource Planning Model Output
Case: CWL 2

Data Item	Units	Description	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
ENERGY REQUIREMENTS	GWH		1251.00	1278.00	1304.00	1329.00	1358.00	1393.00	1427.00	1461.00	1495.00	1532.00	1569.00	1607.00	1645.00	1663.00	1695.00	1727.00	1760.00	1792.00
PEAK DEMAND	MW		285.00	289.00	294.00	300.00	306.00	312.00	318.00	325.00	332.00	338.00	345.00	353.00	360.00	366.00	373.00	381.00	387.00	394.00
REQUIRED RESERVES	MW		46.40	47.05	47.86	48.84	49.82	50.79	51.77	52.91	54.05	55.03	56.17	57.47	58.61	59.58	60.72	62.03	63.00	64.14
TOTAL CAPACITY RESPONSIBILITY	MW		331.40	336.05	341.86	348.84	355.82	362.79	369.77	377.91	386.05	393.03	401.17	410.47	418.61	425.58	433.72	443.03	450.00	458.14
TOTAL FIRM RESOURCES	MW		388.17	388.17	388.17	349.67	355.85	362.82	369.80	377.94	386.08	445.04	445.04	445.04	445.04	445.04	445.04	445.04	450.04	458.18
RESERVE SURPLUS/(DEFICIT)	MW		56.77	52.12	46.31	0.83	0.03	0.03	0.03	0.03	0.03	52.02	43.88	34.58	26.44	19.46	11.32	2.02	0.04	0.04
RESERVE MARGIN	%		36%	34%	32%	17%	16%	16%	16%	16%	16%	32%	29%	26%	24%	22%	19%	17%	16%	16%
DUMP ENERGY	GWH		127.82	121.26	114.14	112.98	107.84	101.34	96.74	95.08	96.36	57.23	54.80	52.60	52.59	51.54	43.19	41.01	41.04	41.86
ECONOMY INTERCHANGE PURCHASE ENERGY	GWH		101.57	120.22	133.88	162.11	187.85	212.86	238.98	269.50	311.23	174.28	202.26	228.56	271.87	284.60	285.87	304.22	345.15	385.51
ECONOMY INTERCHANGE SALES ENERGY	GWH		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ECONOMY INTERCHANGE PURCHASE COST	$000		$4,667.99	$5,491.65	$6,266.01	$7,804.70	$9,353.02	$10,972.75	$12,741.77	$14,805.22	$17,645.63	$9,082.00	$10,976.10	$12,931.38	$15,994.89	$17,600.19	$18,544.88	$20,288.58	$23,471.34	$27,238.32
ECONOMY INTERCHANGE SALES COST	$000		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
EMERGENCY ENERGY	GWH		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EMERGENCY COST	$000		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TRANSACTION PURCHASE COST	$000		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TRANSACTION SALES COST	$000		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
FIRM CAPACITY	MW	7FA Combined Cycle Fully Fired (25% ownership)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FIRM CAPACITY	MW	7FA Combined Cycle Fully Fired (25% ownership) :2022:700	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	95.38	95.38	95.38	95.38	95.38	95.38	95.38	95.38	95.38
FIRM CAPACITY	MW	Ameresco/Columbia LFG	7.20	7.20	7.20	7.20	7.20	7.20	7.20	7.20	7.20	7.20	7.20	7.20	7.20	7.20	7.20	7.20	7.20	7.20
FIRM CAPACITY	MW	Blue Grass Ridge	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93
FIRM CAPACITY	MW	Columbia Energy Center	144.00	144.00	144.00	144.00	144.00	144.00	144.00	144.00	144.00	144.00	144.00	144.00	144.00	144.00	144.00	144.00	144.00	144.00
FIRM CAPACITY	MW	CWL Unit 5	16.50	16.50	16.50	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FIRM CAPACITY	MW	CWL Unit 6	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50
FIRM CAPACITY	MW	CWL Unit 7	22.00	22.00	22.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FIRM CAPACITY	MW	CWL Unit 8	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00
FIRM CAPACITY	MW	Distributed Generation	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50
FIRM CAPACITY	MW	Iatan 2	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00
FIRM CAPACITY	MW	Market Capacity	0.00	0.00	0.00	0.00	6.18	13.16	20.13	28.27	36.41	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.00	13.14
FIRM CAPACITY	MW	Nearman Creek	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FIRM CAPACITY	MW	NextEra Crystal Lake 3 Wind Farm	1.54	1.54	1.54	1.54	1.54	1.54	1.54	1.54	1.54	1.54	1.54	1.54	1.54	1.54	1.54	1.54	1.54	1.54
FIRM CAPACITY	MW	PPA A	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FIRM CAPACITY	MW	Prairie State Energy Campus	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00
FIRM CAPACITY	MW	Sikeston	66.00	66.00	66.00	66.00	66.00	66.00	66.00	66.00	66.00	66.00	66.00	66.00	66.00	66.00	66.00	66.00	66.00	66.00
FIRM CAPACITY	MW	Wartsila Block x6	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FIRM CAPACITY	MW	Wartsila Engine	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
MAXIMUM CAPACITY	MW	7FA Combined Cycle Fully Fired (25% ownership)	381.50	381.50	381.50	381.50	381.50	381.50	381.50	381.50	381.50	381.50	381.50	381.50	381.50	381.50	381.50	381.50	381.50	381.50
MAXIMUM CAPACITY	MW	7FA Combined Cycle Fully Fired (25% ownership) :2022:700	381.50	381.50	381.50	381.50	381.50	381.50	381.50	381.50	381.50	381.50	381.50	381.50	381.50	381.50	381.50	381.50	381.50	381.50
MAXIMUM CAPACITY	MW	Ameresco/Columbia LFG	7.20	7.20	7.20	7.20	7.20	7.20	7.20	7.20	7.20	7.20	7.20	7.20	7.20	7.20	7.20	7.20	7.20	7.20
MAXIMUM CAPACITY	MW	Blue Grass Ridge	6.30	6.30	6.30	6.30	6.30	6.30	6.30	6.30	6.30	6.30	6.30	6.30	6.30	6.30	6.30	6.30	6.30	6.30
MAXIMUM CAPACITY	MW	Columbia Energy Center	144.00	144.00	144.00	144.00	144.00	144.00	144.00	144.00	144.00	144.00	144.00	144.00	144.00	144.00	144.00	144.00	144.00	144.00
MAXIMUM CAPACITY	MW	CWL Unit 5	16.50	16.50	16.50	16.50	16.50	16.50	16.50	16.50	16.50	16.50	16.50	16.50	16.50	16.50	16.50	16.50	16.50	16.50
MAXIMUM CAPACITY	MW	CWL Unit 6	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50
MAXIMUM CAPACITY	MW	CWL Unit 7	22.00	22.00	22.00	22.00	22.00	22.00	22.00	22.00	22.00	22.00	22.00	22.00	22.00	22.00	22.00	22.00	22.00	22.00
MAXIMUM CAPACITY	MW	CWL Unit 8	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00
MAXIMUM CAPACITY	MW	Distributed Generation	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50
MAXIMUM CAPACITY	MW	Iatan 2	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00
MAXIMUM CAPACITY	MW	Market Capacity	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
MAXIMUM CAPACITY	MW	Nearman Creek	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00
MAXIMUM CAPACITY	MW	NextEra Crystal Lake 3 Wind Farm	10.50	10.50	10.50	10.50	10.50	10.50	10.50	10.50	10.50	10.50	10.50	10.50	10.50	10.50	10.50	10.50	10.50	10.50
MAXIMUM CAPACITY	MW	PPA A	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00
MAXIMUM CAPACITY	MW	Prairie State Energy Campus	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00
MAXIMUM CAPACITY	MW	Sikeston	66.00	66.00	66.00	66.00	66.00	66.00	66.00	66.00	66.00	66.00	66.00	66.00	66.00	66.00	66.00	66.00	66.00	66.00
MAXIMUM CAPACITY	MW	Wartsila Block x6	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10
MAXIMUM CAPACITY	MW	Wartsila Engine	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10
GENERATION	GWH	7FA Combined Cycle Fully Fired (25% ownership)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
GENERATION	GWH	7FA Combined Cycle Fully Fired (25% ownership) :2022:700	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	227.02	231.59	236.18	234.30	237.03	254.64	260.80	257.53	252.09
GENERATION	GWH	Ameresco/Columbia LFG	56.76	56.76	56.76	56.92	56.76	56.76	56.76	56.92	56.76	56.76	56.76	56.92	56.76	56.76	56.76	56.92	56.76	56.76
GENERATION	GWH	Blue Grass Ridge	15.45	15.45	15.45	15.49	15.45	15.45	15.45	15.49	15.45	15.45	15.45	15.49	15.45	15.45	15.45	15.49	15.45	15.45
GENERATION	GWH	Columbia Energy Center	133.07	134.97	139.98	133.57	134.82	138.27	141.46	140.28	137.09	46.78	48.69	50.37	50.07	51.47	55.99	58.10	56.70	54.71
GENERATION	GWH	CWL Unit 5	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
GENERATION	GWH	CWL Unit 6	0.32	0.30	0.31	0.46	0.45	0.45	0.46	0.44	0.42	0.20	0.22	0.24	0.24	0.25	0.29	0.30	0.29	0.27
GENERATION	GWH	CWL Unit 7	0.82	0.79	0.82	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
GENERATION	GWH	CWL Unit 8	3.03	3.00	3.16	2.67	2.67	2.73	2.81	2.71	2.61	1.06	1.14	1.22	1.20	1.27	1.44	1.51	1.44	1.35
GENERATION	GWH	Distributed Generation	0.25	0.23	0.23	0.30	0.29	0.28	0.28	0.26	0.26	0.13	0.14	0.16	0.15	0.17	0.20	0.20	0.19	0.18
GENERATION	GWH	Iatan 2	175.20	175.20	175.20	175.68	175.20	175.20	175.20	175.68	175.20	175.20	175.20	175.68	175.20	175.20	175.20	175.68	175.20	175.20
GENERATION	GWH	Market Capacity	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
GENERATION	GWH	Nearman Creek	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
GENERATION	GWH	NextEra Crystal Lake 3 Wind Farm	41.39	41.39	41.39	41.50	41.39	41.39	41.39	41.50	41.39	41.39	41.39	41.50	41.39	41.39	41.39	41.50	41.39	41.39
GENERATION	GWH	PPA A	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
GENERATION	GWH	Prairie State Energy Campus	394.20	394.20	394.20	395.28	394.20	394.20	394.20	395.28	394.20	394.20	394.20	395.28	394.20	394.20	394.20	395.28	394.20	394.20
GENERATION	GWH	Sikeston	456.75	456.75	456.75	458.00	456.75	456.75	456.75	458.00	456.75	456.75	456.75	458.00	456.75	456.75	456.75	458.00	456.75	456.75
GENERATION	GWH	Wartsila Block x6	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
GENERATION	GWH	Wartsila Engine	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CAPACITY FACTOR	%	7FA Combined Cycle Fully Fired (25% ownership)																		
CAPACITY FACTOR	%	7FA Combined Cycle Fully Fired (25% ownership) :2022:700										27.17%	27.72%	28.19%	28.04%	28.37%	30.48%	31.13%	30.82%	30.17%
CAPACITY FACTOR	%	Ameresco/Columbia LFG	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%
CAPACITY FACTOR	%	Blue Grass Ridge	28.00%	28.00%	28.00%	28.00%	28.00%	28.00%	28.00%	28.00%	28.00%	28.00%	28.00%	28.00%	28.00%	28.00%	28.00%	28.00%	28.00%	28.00%
CAPACITY FACTOR	%	Columbia Energy Center	10.55%	10.70%	11.10%	10.56%	10.69%	10.96%	11.21%	11.09%	10.87%	3.71%	3.86%	3.98%	3.97%	4.08%	4.44%	4.59%	4.49%	4.34%
CAPACITY FACTOR	%	CWL Unit 5	0.00%	0.00%	0.00%															

Table B-1 Partner Future Base
Columbia Water and Light
Burns & McDonnell Project No. 67546
2012 IRP

Resource Planning Model Output
Case: CWL 2

Data Item	Units	Description	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
CAPACITY FACTOR	%	CWL Unit 6	0.30%	0.28%	0.28%	0.42%	0.41%	0.41%	0.42%	0.40%	0.39%	0.19%	0.20%	0.22%	0.22%	0.23%	0.27%	0.28%	0.26%	0.25%
CAPACITY FACTOR	%	CWL Unit 7	0.42%	0.41%	0.42%															
CAPACITY FACTOR	%	CWL Unit 8	0.99%	0.98%	1.03%	0.87%	0.87%	0.89%	0.92%	0.88%	0.85%	0.35%	0.37%	0.40%	0.39%	0.41%	0.47%	0.49%	0.47%	0.44%
CAPACITY FACTOR	%	Distributed Generation	0.23%	0.21%	0.21%	0.27%	0.26%	0.26%	0.26%	0.24%	0.24%	0.12%	0.13%	0.14%	0.14%	0.15%	0.18%	0.19%	0.18%	0.16%
CAPACITY FACTOR	%	Iatan 2	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
CAPACITY FACTOR	%	Market Capacity					0.00%	0.00%	0.00%	0.00%	0.00%								0.00%	0.00%
CAPACITY FACTOR	%	Nearman Creek																		
CAPACITY FACTOR	%	NextEra Crystal Lake 3 Wind Farm	45.00%	45.00%	45.00%	45.00%	45.00%	45.00%	45.00%	45.00%	45.00%	45.00%	45.00%	45.00%	45.00%	45.00%	45.00%	45.00%	45.00%	45.00%
CAPACITY FACTOR	%	PPA A																		
CAPACITY FACTOR	%	Prairie State Energy Campus	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%
CAPACITY FACTOR	%	Sikeston	79.00%	79.00%	79.00%	79.00%	79.00%	79.00%	79.00%	79.00%	79.00%	79.00%	79.00%	79.00%	79.00%	79.00%	79.00%	79.00%	79.00%	79.00%
CAPACITY FACTOR	%	Wartsila Block x6																		
CAPACITY FACTOR	%	Wartsila Engine																		
TOTAL O AND M COST	$000	7FA Combined Cycle Fully Fired (25% ownership)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL O AND M COST	$000	7FA Combined Cycle Fully Fired (25% ownership) :2022 700	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$2,341.09	$2,440.36	$2,543.79	$2,625.19	$2,728.56	$2,900.78	$3,030.06	$3,120.86	$3,203.81
TOTAL PURCHASE COST	$000	Ameresco/Columbia LFG	$3,405.89	$3,405.89	$3,405.89	$3,415.22	$3,405.89	$3,405.89	$3,405.89	$3,415.22	$3,405.89	$3,405.89	$3,405.89	$3,415.22	$3,405.89	$3,405.89	$3,405.89	$3,415.22	$3,405.89	$3,405.89
TOTAL PURCHASE COST	$000	Blue Grass Ridge	$1,004.42	$1,004.42	$1,004.42	$1,007.17	$1,004.42	$1,004.42	$1,004.42	$1,007.17	$1,004.42	$1,004.42	$1,004.42	$1,007.17	$1,004.42	$1,004.42	$1,004.42	$1,007.17	$1,004.42	$1,004.42
TOTAL O AND M COST	$000	Columbia Energy Center	$12,158.17	$12,465.95	$12,788.01	$13,094.07	$13,424.15	$14,115.49	$14,475.67	$14,834.82	$15,198.00	$15,355.34	$15,744.06	$16,142.00	$16,544.76	$16,962.19	$17,398.86	$17,735.59	$18,352.13	$18,988.32
TOTAL O AND M COST	$000	CWL Unit 5	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL O AND M COST	$000	CWL Unit 6	$1,760.47	$1,841.77	$1,906.60	$1,981.77	$2,050.63	$2,122.50	$2,197.26	$2,272.65	$2,351.22	$2,418.10	$2,503.97	$2,593.08	$2,683.51	$2,778.71	$2,879.27	$2,981.20	$3,084.13	$3,190.27
TOTAL O AND M COST	$000	CWL Unit 7	$1,789.24	$1,850.86	$1,916.75	$325.47	$336.86	$348.65	$360.85	$373.48	$386.56	$400.09	$414.09	$428.58	$443.58	$459.11	$475.18	$491.81	$509.02	$526.84
TOTAL O AND M COST	$000	CWL Unit 8	$443.17	$458.66	$474.90	$490.91	$508.09	$525.95	$544.47	$563.39	$582.97	$601.02	$622.18	$644.08	$666.60	$690.05	$714.51	$739.64	$765.39	$792.01
TOTAL O AND M COST	$000	Distributed Generation	$56.39	$54.02	$55.88	$74.77	$74.82	$76.06	$78.62	$76.80	$77.80	$40.36	$45.67	$52.26	$52.99	$58.95	$72.05	$77.95	$76.41	$73.49
TOTAL PURCHASE COST	$000	Iatan 2	$8,049.42	$8,235.00	$8,248.59	$8,386.67	$8,521.14	$8,661.30	$8,806.72	$8,968.17	$9,115.07	$9,278.01	$9,449.70	$9,638.27	$9,810.62	$10,001.58	$10,201.31	$10,422.80	$10,623.54	$10,847.80
TOTAL PURCHASE COST	$000	Market Capacity	$0.00	$0.00	$0.00	$0.00	$185.33	$402.10	$636.91	$925.73	$1,234.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$223.02	$606.80
TOTAL PURCHASE COST	$000	Nearman Creek	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL PURCHASE COST	$000	NextEra Crystal Lake 3 Wind Farm	$1,800.51	$1,841.90	$1,862.59	$1,867.70	$1,862.59	$1,862.59	$1,862.59	$1,867.70	$1,862.59	$1,862.59	$1,862.59	$1,867.70	$1,862.59	$1,862.59	$1,862.59	$1,867.70	$1,862.59	$1,862.59
TOTAL PURCHASE COST	$000	PPA A	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL PURCHASE COST	$000	Prairie State Energy Campus	$23,803.44	$25,262.06	$23,723.22	$22,971.09	$22,994.74	$23,476.78	$24,287.24	$25,097.02	$25,933.88	$26,811.01	$27,711.95	$28,696.49	$29,628.01	$30,644.88	$31,649.65	$32,744.04	$33,823.81	$34,995.23
TOTAL PURCHASE COST	$000	Sikeston	$24,617.16	$28,230.89	$28,958.47	$29,080.55	$28 772.06	$29,555.44	$30,589.88	$31,705.84	$32,768.65	$33,915.54	$35,102.59	$36,383.19	$37,602.77	$38,918.86	$40,281.03	$41,750.54	$43,150.05	$44,660.30
TOTAL O AND M COST	$000	Wartsila Block x6	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL O AND M COST	$000	Wartsila Engine	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
FIXED O AND M COST	$000	7FA Combined Cycle Fully Fired (25% ownership)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
FIXED O AND M COST	$000	7FA Combined Cycle Fully Fired (25% ownership) :2022 700	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$1,508.47	$1,561.26	$1,615.91	$1,672.46	$1,731.00	$1,791.59	$1,854.29	$1,919.19	$1,986.36
CAPACITY COST	$000	Ameresco/Columbia LFG	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
CAPACITY COST	$000	Blue Grass Ridge	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
FIXED O AND M COST	$000	Columbia Energy Center	$11,895.51	$12,192.89	$12,497.72	$12,810.16	$13,130.41	$13,806.72	$14,151.88	$14,505.68	$14,868.32	$15,240.03	$15,621.03	$16,011.56	$16,411.85	$16,822.14	$17,242.70	$17,567.87	$18,182.75	$18,819.14
FIXED O AND M COST	$000	CWL Unit 5	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
FIXED O AND M COST	$000	CWL Unit 6	$1,763.74	$1,825.47	$1,889.37	$1,955.49	$2,023.94	$2,094.77	$2,168.09	$2,243.97	$2,322.51	$2,403.80	$2,487.93	$2,575.01	$2,665.14	$2,758.42	$2,854.96	$2,954.89	$3,058.31	$3,165.35
FIXED O AND M COST	$000	CWL Unit 7	$1,763.66	$1,825.38	$1,889.27	$325.47	$336.86	$348.65	$360.85	$373.48	$386.56	$400.09	$414.09	$428.58	$443.58	$459.11	$475.18	$491.81	$509.02	$526.84
FIXED O AND M COST	$000	CWL Unit 8	$439.81	$455.20	$471.13	$487.62	$504.69	$522.35	$540.64	$559.56	$579.14	$599.41	$620.39	$642.11	$664.58	$687.84	$711.92	$736.83	$762.62	$789.31
FIXED O AND M COST	$000	Distributed Generation	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
CAPACITY COST	$000	Iatan 2	$5,050.00	$5,125.20	$5,014.40	$5,022.40	$5,022.40	$5,022.40	$5,022.40	$5,022.40	$5,022.40	$5,022.40	$5,022.40	$5,022.40	$5,022.40	$5,022.40	$5,022.40	$5,022.40	$5,022.40	$5,022.40
CAPACITY COST	$000	Market Capacity	$0.00	$0.00	$0.00	$0.00	$185.33	$402.10	$636.91	$925.73	$1,234.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$223.02	$606.80
CAPACITY COST	$000	Nearman Creek	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
CAPACITY COST	$000	NextEra Crystal Lake 3 Wind Farm	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
CAPACITY COST	$000	PPA A	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
CAPACITY COST	$000	Prairie State Energy Campus	$18,600.00	$19,625.00	$18,165.00	$17,200.00	$17,200.00	$17,524.36	$18,137.72	$18,772.54	$19,429.58	$20,109.61	$20,813.45	$21,541.92	$22,295.89	$23,076.24	$23,883.91	$24,719.85	$25,585.03	$26,480.51
CAPACITY COST	$000	Sikeston	$13 527.36	$14,464.55	$14,813.04	$14,612.40	$13,854.72	$14,116.00	$14,610.06	$15,121.41	$15,650.66	$16,198.43	$16,765.38	$17,352.17	$17,959.49	$18,588.07	$19,238.66	$19,912.01	$20,608.93	$21,330.24
FIXED O AND M COST	$000	Wartsila Block x6	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
FIXED O AND M COST	$000	Wartsila Engine	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
ANNUAL DEBT SERVICE	$000	7FA Combined Cycle Fully Fired (25% ownership) :2022 700										$9,981.25	$9,981.25	$9,981.25	$9,981.25	$9,981.25	$9,981.25	$9,981.25	$9,981.25	$9,981.25
VARIABLE O AND M COSTS	$/MWH	7FA Combined Cycle Fully Fired (25% ownership)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$/MWH	7FA Combined Cycle Fully Fired (25% ownership) :2022 700	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$3.67	$3.80	$3.93	$4.07	$4.21	$4.36	$4.51	$4.67	$4.83
ENERGY COSTS	$/MWH	Ameresco/Columbia LFG	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00
ENERGY COSTS	$/MWH	Blue Grass Ridge	$65.00	$65.00	$65.00	$65.00	$65.00	$65.00	$65.00	$65.00	$65.00	$65.00	$65.00	$65.00	$65.00	$65.00	$65.00	$65.00	$65.00	$65.00
VARIABLE O AND M COSTS	$/MWH	Columbia Energy Center	$1.97	$2.02	$2.07	$2.13	$2.18	$2.23	$2.29	$2.35	$2.40	$2.47	$2.53	$2.59	$2.65	$2.72	$2.79	$2.89	$2.99	$3.09
VARIABLE O AND M COSTS	$/MWH	CWL Unit 5	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$/MWH	CWL Unit 6	$51.62	$53.42	$55.29	$57.23	$59.23	$61.30	$63.45	$65.67	$67.97	$70.35	$72.81	$75.36	$77.99	$80.72	$83.55	$86.47	$89.50	$92.63
VARIABLE O AND M COSTS	$/MWH	CWL Unit 7	$31.35	$32.44	$33.58	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$/MWH	CWL Unit 8	$1.11	$1.15	$1.19	$1.23	$1.27	$1.32	$1.37	$1.41	$1.46	$1.51	$1.57	$1.62	$1.68	$1.74	$1.80	$1.86	$1.93	$1.99
VARIABLE O AND M COSTS	$/MWH	Distributed Generation	$228.06	$236.04	$244.30	$252.85	$261.70	$270.86	$280.34	$290.15	$300.31	$310.82	$321.70	$332.96	$344.61	$356.67	$369.15	$382.07	$395.45	$409.29
ENERGY COSTS	$/MWH	Iatan 2	$17.12	$17.75	$18.46	$19.15	$19.97	$20.77	$21.60	$22.46	$23.36	$24.29	$25.27	$26.28	$27.33	$28.42	$29.56	$30.74	$31.97	$33.25
ENERGY COSTS	$/MWH	Market Capacity	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
ENERGY COSTS	$/MWH	Nearman Creek	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
ENERGY COSTS	$/MWH	NextEra Crystal Lake 3 Wind Farm	$43.50	$44.50	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00
ENERGY COSTS	$/MWH	PPA A	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
ENERGY COSTS	$/MWH	Prairie State Energy Campus	$13.20	$14.30	$14.10	$14.60	$14.70	$15.10	$15.60	$16.00	$16.50	$17.00	$17.50	$18.10	$18.60	$19.20	$19.70	$20.30	$20.90	$21.60
ENERGY COSTS	$/MWH	Sikeston	$24.28	$30.14	$30.97	$31.59	$32.66	$33.80	$34.99	$36.21	$37.48	$38.79	$40.15	$41.55	$43.01	$44.51	$46.07	$47.68	$49.35	$51.08
VARIABLE O AND M COSTS	$/MWH	Wartsila Block x6	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$/MWH	Wartsila Engine	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$000	7FA Combined Cycle Fully Fired (25% ownership)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$000	7FA Combined Cycle Fully Fired (25% ownership) :2022.700	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$832.62	$879.10	$927.89	$952.73	$997.56	$1,109.19	$1,175.76	$1,201.67	$1,217.44
ENERGY COSTS	$000	Ameresco/Columbia LFG	$3,405.89	$3,405.89	$3,405.89	$3,415.22	$3,405.89	$3,405.89	$3,405.89	$3,415.22	$3,405.89	$3,405.89	$3,405.89	$3,415.22	$3,405.89	$3,405.89	$3,405.89	$3,415.22	$3,405.89	$3,405.89
ENERGY COSTS	$000	Blue Grass Ridge	$1,004.42	$1,004.42	$1,004.42	$1,007.17	$1,004.42	$1,004.42	$1,004.42	$1,007.17	$1,004.42	$1,004.42	$1,004.42	$1,007.17	$1,004.42	$1,004.42	$1,004.42	$1,007.17	$1,004.42	$1,004.42
VARIABLE O AND M COSTS	$000	Columbia Energy Center	$262.66	$273.06	$290.29	$283.91	$293.74	$308.78	$323.79	$329.14	$329.68	$115.31	$123.03	$130.44	$132.91	$140.05	$156.16	$167.72	$169.38	$169.18
VARIABLE O AND M COSTS	$000	CWL Unit 5	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$000	CWL Unit 6	$16.73	$16.29	$17.23	$26.27	$26.70	$27.73	$29.17	$28.67	$28.71	$14.30	$16.04	$18.07	$18.37	$20.30	$24.31	$26.32	$25.82	$24.92

Table B-1 Partner Future Base
Columbia Water and Light
Burns & McDonnell Project No. 67546
2012 IRP

Resource Planning Model Output
Case: CWL 2

Data Item	Units	Description	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
VARIABLE O AND M COSTS	$000	CWL Unit 7	$25.58	$25.48	$27.48	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$000	CWL Unit 8	$3.37	$3.45	$3.76	$3.28	$3.40	$3.60	$3.83	$3.83	$3.82	$1.81	$1.78	$1.97	$2.02	$2.21	$2.59	$2.80	$2.77	$2.89
VARIABLE O AND M COSTS	$000	Distributed Generation	$56.39	$54.02	$55.88	$74.77	$74.82	$76.06	$78.62	$76.80	$77.80	$40.36	$45.67	$52.26	$52.99	$58.95	$72.05	$77.95	$76.41	$73.49
ENERGY COSTS	$000	Iatan 2	$2,999.42	$3,109.80	$3,234.19	$3,364.27	$3,498.74	$3,638.90	$3,784.32	$3,945.77	$4,092.67	$4,255.61	$4,427.30	$4,616.67	$4,788.22	$4,979.18	$5,178.91	$5,400.40	$5,601.14	$5,825.40
ENERGY COSTS	$000	Market Capacity	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
ENERGY COSTS	$000	Nearman Creek	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
ENERGY COSTS	$000	NextEra Crystal Lake 3 Wind Farm	$1,800.51	$1,841.90	$1,862.59	$1,867.70	$1,862.59	$1,862.59	$1,862.59	$1,867.70	$1,862.59	$1,862.59	$1,862.59	$1,867.70	$1,862.59	$1,862.59	$1,862.59	$1,867.70	$1,862.59	$1,862.59
ENERGY COSTS	$000	PPA A	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
ENERGY COSTS	$000	Prairie State Energy Campus	$5,203.44	$5,637.06	$5,558.22	$5,771.09	$5,794.74	$5,952.42	$6,149.52	$6,324.46	$6,504.30	$6,701.40	$6,898.50	$7,154.57	$7,332.12	$7,568.64	$7,765.74	$8,024.18	$8,238.78	$8,514.72
ENERGY COSTS	$000	Sikeston	$11,089.60	$13,766.34	$14,145.44	$14,468.15	$14,917.34	$15,439.44	$15,979.82	$16,584.43	$17,117.99	$17,717.11	$18,337.21	$19,031.02	$19,643.28	$20,330.80	$21,042.37	$21,838.53	$22,541.12	$23,330.06
VARIABLE O AND M COSTS	$000	Wartsila Block x6	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$000	Wartsila Engine	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL FUEL COST	$000	7FA Combined Cycle Fully Fired (25% ownership)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL FUEL COST	$000	7FA Combined Cycle Fully Fired (25% ownership) 2022:700	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$12,241.11	$13,070.91	$13,853.00	$14,540.53	$15,439.50	$16,920.39	$17,514.34	$17,800.90	$18,379.48
TOTAL FUEL COST	$000	Ameresco/Columbia LFG	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL FUEL COST	$000	Blue Grass Ridge	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL FUEL COST	$000	Columbia Energy Center	$8,181.00	$8,656.58	$9,189.70	$9,185.83	$9,770.26	$10,491.90	$11,108.31	$11,677.44	$12,282.45	$4,371.86	$4,764.62	$5,122.96	$5,390.12	$5,817.22	$6,467.97	$6,776.78	$6,806.79	$6,925.50
TOTAL FUEL COST	$000	CWL Unit 5	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL FUEL COST	$000	CWL Unit 6	$27.63	$27.10	$28.30	$43.67	$45.39	$47.63	$50.02	$50.49	$52.75	$26.04	$29.55	$33.44	$34.78	$38.98	$46.08	$48.70	$47.50	$46.56
TOTAL FUEL COST	$000	CWL Unit 7	$62.33	$61.19	$64.53	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL FUEL COST	$000	CWL Unit 8	$200.97	$207.73	$223.78	$198.45	$209.02	$223.92	$238.14	$243.91	$253.53	$106.47	$119.55	$132.79	$138.92	$154.07	$178.30	$188.72	$185.20	$183.41
TOTAL FUEL COST	$000	Distributed Generation	$55.92	$53.57	$55.42	$74.09	$74.15	$75.37	$77.89	$76.10	$77.12	$39.96	$45.21	$51.74	$52.46	$58.38	$71.32	$77.14	$75.62	$72.73
TOTAL FUEL COST	$000	Iatan 2	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL FUEL COST	$000	Market Capacity	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL FUEL COST	$000	Nearman Creek	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL FUEL COST	$000	NextEra Crystal Lake 3 Wind Farm	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL FUEL COST	$000	PPA A	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL FUEL COST	$000	Prairie State Energy Campus	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL FUEL COST	$000	Sikeston	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL FUEL COST	$000	Wartsila Block x6	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL FUEL COST	$000	Wartsila Engine	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL VARIABLE COST	$/MWH	7FA Combined Cycle Fully Fired (25% ownership)																		
TOTAL VARIABLE COST	$/MWH	7FA Combined Cycle Fully Fired (25% ownership) 2022:700										$57.59	$60.24	$62.58	$66.13	$69.35	$70.80	$71.67	$73.79	$77.74
TOTAL ENERGY COSTS	$/MWH	Ameresco/Columbia LFG	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00
TOTAL ENERGY COSTS	$/MWH	Blue Grass Ridge	$65.00	$65.00	$65.00	$65.00	$65.00	$65.00	$65.00	$65.00	$65.00	$65.00	$65.00	$65.00	$65.00	$65.00	$65.00	$65.00	$65.00	$65.00
TOTAL VARIABLE COST	$/MWH	Columbia Energy Center	$63.45	$66.16	$67.72	$70.90	$74.65	$78.11	$80.82	$85.59	$92.00	$95.93	$100.38	$104.30	$110.31	$115.74	$118.12	$119.52	$123.05	$129.67
TOTAL VARIABLE COST	$/MWH	CWL Unit 5																		
TOTAL VARIABLE COST	$/MWH	CWL Unit 6	$136.85	$142.26	$146.12	$152.77	$159.93	$166.61	$172.27	$181.31	$192.87	$198.45	$206.94	$214.79	$225.62	$235.76	$241.91	$246.52	$254.14	$266.09
TOTAL VARIABLE COST	$/MWH	CWL Unit 7	$107.72	$110.37	$112.43															
TOTAL VARIABLE COST	$/MWH	CWL Unit 8	$67.44	$70.33	$71.96	$75.65	$79.70	$83.40	$86.24	$91.47	$98.54	$101.76	$106.54	$110.71	$117.18	$123.03	$125.65	$127.10	$130.79	$137.79
TOTAL VARIABLE COST	$/MWH	Distributed Generation	$454.18	$470.10	$486.59	$503.39	$521.05	$539.27	$558.07	$577.67	$597.99	$618.55	$640.17	$662.63	$685.75	$709.73	$734.56	$760.16	$786.81	$814.32
TOTAL ENERGY COSTS	$/MWH	Iatan 2	$17.12	$17.75	$18.46	$19.15	$19.97	$20.77	$21.60	$22.46	$23.36	$24.29	$25.27	$26.28	$27.33	$28.42	$29.56	$30.74	$31.97	$33.25
TOTAL ENERGY COSTS	$/MWH	Market Capacity																		
TOTAL ENERGY COSTS	$/MWH	Nearman Creek																		
TOTAL ENERGY COSTS	$/MWH	NextEra Crystal Lake 3 Wind Farm	$43.50	$44.50	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00
TOTAL ENERGY COSTS	$/MWH	PPA A																		
TOTAL ENERGY COSTS	$/MWH	Prairie State Energy Campus	$13.20	$14.30	$14.10	$14.60	$14.70	$15.10	$15.60	$16.00	$16.50	$17.00	$17.50	$18.10	$18.60	$19.20	$19.70	$20.30	$20.90	$21.60
TOTAL ENERGY COSTS	$/MWH	Sikeston	$24.28	$30.14	$30.97	$31.59	$32.66	$33.80	$34.99	$36.21	$37.48	$38.79	$40.15	$41.55	$43.01	$44.51	$46.07	$47.68	$49.35	$51.08
TOTAL VARIABLE COST	$/MWH	Wartsila Block x6																		
TOTAL VARIABLE COST	$/MWH	Wartsila Engine																		
SYSTEM EFFLUENT EXPENSE	$000	NOx	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
SYSTEM EFFLUENT EXPENSE	$000	CO2	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
SYSTEM EFFLUENT EXPENSE	$000	SO2	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
SYSTEM EFFLUENT EXPENSE	$000	Hg	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
SYSTEM EFFLUENT EXPENSE	$000	CO	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
SUMMARY OF COSTS																				
TOTAL FIXED COSTS	$000		$15,863	$16,299	$16,747	$15,579	$15,996	$16,772	$17,221	$17,683	$18,157	$20,152	$20,705	$21,273	$21,858	$22,459	$23,076	$23,606	$24,432	$25,287
TOTAL VARIABLE (EXCL. FUEL) COSTS	$000		$4,923	$5,864	$6,661	$8,193	$9,752	$11,389	$13,177	$15,244	$18,086	$10,086	$12,042	$14,062	$17,154	$18,819	$19,909	$21,739	$24,947	$28,726
TOTAL FUEL COSTS	$000		$8,528	$9,006	$9,562	$9,502	$10,099	$10,839	$11,474	$12,048	$12,666	$16,785	$18,030	$19,194	$20,157	$21,508	$23,674	$24,606	$24,916	$25,608
TOTAL DEBT SERVICE COSTS	$000		$0	$0	$0	$0	$0	$0	$0	$0	$0	$9,981	$9,981	$9,981	$9,981	$9,981	$9,981	$9,981	$9,981	$9,981
TOTAL PURCHASE COSTS	$000		$62,681	$67,980	$67,203	$66,728	$66,746	$68,369	$70,594	$72,987	$75,325	$76,277	$78,537	$81,009	$83,314	$85,838	$88,405	$91,207	$94,093	$97,383
TOTAL COSTS	$000		$91,994	$99,149	$100,173	$100,002	$102,593	$107,369	$112,467	$117,961	$124,233	$133,282	$139,295	$145,519	$152,464	$158,605	$165,046	$171,139	$178,370	$186,985

NPV @ 4.0% ($000): $1,604,241

Table B-2 PF Gas Sensitivity
Columbia Water and Light
Burns & McDonnell Project No. 67546
2012 IRP

Resource Planning Model Output
Case: CWL 2

Data Item	Units	Description	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
ENERGY REQUIREMENTS	GWH		1251.00	1278.00	1304.00	1329.00	1358.00	1393.00	1427.00	1461.00	1495.00	1532.00	1569.00	1607.00	1645.00	1663.00	1695.00	1727.00	1760.00	1792.00
PEAK DEMAND	MW		285.00	289.00	294.00	300.00	306.00	312.00	318.00	325.00	332.00	338.00	345.00	353.00	360.00	366.00	373.00	381.00	387.00	394.00
REQUIRED RESERVES	MW		46.40	47.05	47.86	48.84	49.82	50.79	51.77	52.91	54.05	55.03	56.17	57.47	58.61	59.58	60.72	62.03	63.00	64.14
TOTAL CAPACITY RESPONSIBILITY	MW		331.40	336.05	341.86	348.84	355.82	362.79	369.77	377.91	386.05	393.03	401.17	410.47	418.61	425.58	433.72	443.03	450.00	458.14
TOTAL FIRM RESOURCES	MW		388.17	388.17	388.17	349.67	355.85	362.82	369.80	377.94	386.08	445.04	445.04	445.04	445.04	445.04	445.04	445.04	450.04	458.18
RESERVE SURPLUS/(DEFICIT)	MW		56.77	52.12	46.31	0.83	0.03	0.03	0.03	0.03	0.03	52.02	43.88	34.58	26.44	18.46	11.32	2.02	0.04	0.04
RESERVE MARGIN	%		36%	34%	32%	17%	16%	16%	16%	16%	16%	32%	29%	26%	24%	22%	19%	17%	16%	16%
DUMP ENERGY	GWH		153.95	151.08	146.18	149.85	147.78	146.23	144.57	148.07	153.55	87.28	86.25	85.72	87.19	87.40	80.46	78.26	78.98	81.72
ECONOMY INTERCHANGE PURCHASE ENERGY	GWH		162.91	186.89	205.41	233.84	263.63	296.30	327.72	363.60	408.86	305.68	339.76	372.54	417.68	434.89	444.71	467.45	508.20	547.92
ECONOMY INTERCHANGE SALES ENERGY	GWH		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ECONOMY INTERCHANGE PURCHASE COST	$000		$7,563.19	$8,794.46	$9,907.79	$11,349.32	$13,222.53	$15,330.40	$17,527.91	$19,961.75	$23,146.61	$17,768.72	$20,495.03	$23,305.60	$26,929.60	$29,425.39	$31,050.43	$33,450.93	$36,918.80	$41,082.52
ECONOMY INTERCHANGE SALES COST	$000		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
EMERGENCY ENERGY	GWH		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EMERGENCY COST	$000		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TRANSACTION PURCHASE COST	$000		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TRANSACTION SALES COST	$000		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
FIRM CAPACITY	MW	7FA Combined Cycle Fully Fired (25% ownership)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FIRM CAPACITY	MW	7FA Combined Cycle Fully Fired (25% ownership) :2022:700	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	95.38	95.38	95.38	95.38	95.38	95.38	95.38	95.38	95.38
FIRM CAPACITY	MW	Ameresco/Columbia LFG	7.20	7.20	7.20	7.20	7.20	7.20	7.20	7.20	7.20	7.20	7.20	7.20	7.20	7.20	7.20	7.20	7.20	7.20
FIRM CAPACITY	MW	Blue Grass Ridge	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93
FIRM CAPACITY	MW	Columbia Energy Center	144.00	144.00	144.00	144.00	144.00	144.00	144.00	144.00	144.00	144.00	144.00	144.00	144.00	144.00	144.00	144.00	144.00	144.00
FIRM CAPACITY	MW	CWL Unit 5	16.50	16.50	16.50	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FIRM CAPACITY	MW	CWL Unit 6	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50
FIRM CAPACITY	MW	CWL Unit 7	22.00	22.00	22.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FIRM CAPACITY	MW	CWL Unit 8	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00
FIRM CAPACITY	MW	Distributed Generation	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50
FIRM CAPACITY	MW	Iatan 2	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00
FIRM CAPACITY	MW	Market Capacity	0.00	0.00	0.00	0.00	6.18	13.16	20.13	28.27	36.41	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.00	13.14
FIRM CAPACITY	MW	Nearman Creek	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FIRM CAPACITY	MW	NextEra Crystal Lake 3 Wind Farm	1.54	1.54	1.54	1.54	1.54	1.54	1.54	1.54	1.54	1.54	1.54	1.54	1.54	1.54	1.54	1.54	1.54	1.54
FIRM CAPACITY	MW	PPA A	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FIRM CAPACITY	MW	Prairie State Energy Campus	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00
FIRM CAPACITY	MW	Sikeston	66.00	66.00	66.00	66.00	66.00	66.00	66.00	66.00	66.00	66.00	66.00	66.00	66.00	66.00	66.00	66.00	66.00	66.00
FIRM CAPACITY	MW	Wartsila Block x6	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FIRM CAPACITY	MW	Wartsila Engine	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
MAXIMUM CAPACITY	MW	7FA Combined Cycle Fully Fired (25% ownership)	381.50	381.50	381.50	381.50	381.50	381.50	381.50	381.50	381.50	381.50	381.50	381.50	381.50	381.50	381.50	381.50	381.50	381.50
MAXIMUM CAPACITY	MW	7FA Combined Cycle Fully Fired (25% ownership) :2022:700	381.50	381.50	381.50	381.50	381.50	381.50	381.50	381.50	381.50	381.50	381.50	381.50	381.50	381.50	381.50	381.50	381.50	381.50
MAXIMUM CAPACITY	MW	Ameresco/Columbia LFG	7.20	7.20	7.20	7.20	7.20	7.20	7.20	7.20	7.20	7.20	7.20	7.20	7.20	7.20	7.20	7.20	7.20	7.20
MAXIMUM CAPACITY	MW	Blue Grass Ridge	6.30	6.30	6.30	6.30	6.30	6.30	6.30	6.30	6.30	6.30	6.30	6.30	6.30	6.30	6.30	6.30	6.30	6.30
MAXIMUM CAPACITY	MW	Columbia Energy Center	144.00	144.00	144.00	144.00	144.00	144.00	144.00	144.00	144.00	144.00	144.00	144.00	144.00	144.00	144.00	144.00	144.00	144.00
MAXIMUM CAPACITY	MW	CWL Unit 5	16.50	16.50	16.50	16.50	16.50	16.50	16.50	16.50	16.50	16.50	16.50	16.50	16.50	16.50	16.50	16.50	16.50	16.50
MAXIMUM CAPACITY	MW	CWL Unit 6	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50
MAXIMUM CAPACITY	MW	CWL Unit 7	22.00	22.00	22.00	22.00	22.00	22.00	22.00	22.00	22.00	22.00	22.00	22.00	22.00	22.00	22.00	22.00	22.00	22.00
MAXIMUM CAPACITY	MW	CWL Unit 8	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00
MAXIMUM CAPACITY	MW	Distributed Generation	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50
MAXIMUM CAPACITY	MW	Iatan 2	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00
MAXIMUM CAPACITY	MW	Market Capacity	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
MAXIMUM CAPACITY	MW	Nearman Creek	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00
MAXIMUM CAPACITY	MW	NextEra Crystal Lake 3 Wind Farm	10.50	10.50	10.50	10.50	10.50	10.50	10.50	10.50	10.50	10.50	10.50	10.50	10.50	10.50	10.50	10.50	10.50	10.50
MAXIMUM CAPACITY	MW	PPA A	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00
MAXIMUM CAPACITY	MW	Prairie State Energy Campus	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00
MAXIMUM CAPACITY	MW	Sikeston	66.00	66.00	66.00	66.00	66.00	66.00	66.00	66.00	66.00	66.00	66.00	66.00	66.00	66.00	66.00	66.00	66.00	66.00
MAXIMUM CAPACITY	MW	Wartsila Block x6	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10
MAXIMUM CAPACITY	MW	Wartsila Engine	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10
GENERATION	GWH	7FA Combined Cycle Fully Fired (25% ownership)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
GENERATION	GWH	7FA Combined Cycle Fully Fired (25% ownership) :2022:700	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	150.41	151.77	152.88	150.62	151.27	163.79	166.93	163.65	159.81
GENERATION	GWH	Ameresco/Columbia LFG	56.76	56.76	56.76	56.92	56.76	56.76	56.76	56.92	56.76	56.76	56.76	56.92	56.76	56.76	56.76	56.92	56.76	56.76
GENERATION	GWH	Blue Grass Ridge	15.45	15.45	15.45	15.49	15.45	15.45	15.45	15.49	15.45	15.45	15.45	15.49	15.45	15.45	15.45	15.49	15.45	15.45
GENERATION	GWH	Columbia Energy Center	95.91	96.02	98.45	99.37	99.58	100.33	101.23	99.69	97.00	23.11	23.62	24.07	23.78	24.11	26.69	27.48	26.67	25.75
GENERATION	GWH	CWL Unit 5	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
GENERATION	GWH	CWL Unit 6	0.29	0.29	0.30	0.44	0.45	0.45	0.46	0.47	0.49	0.04	0.05	0.05	0.05	0.05	0.08	0.08	0.07	0.07
GENERATION	GWH	CWL Unit 7	4.14	4.23	4.31	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
GENERATION	GWH	CWL Unit 8	1.68	1.63	1.69	1.96	1.99	2.01	2.03	2.04	2.03	0.24	0.26	0.27	0.27	0.29	0.37	0.39	0.37	0.35
GENERATION	GWH	Distributed Generation	0.27	0.27	0.27	0.36	0.38	0.38	0.38	0.40	0.41	0.03	0.03	0.03	0.03	0.04	0.06	0.06	0.06	0.05
GENERATION	GWH	Iatan 2	175.20	175.20	175.20	175.68	175.20	175.20	175.20	175.68	175.20	175.20	175.20	175.68	175.20	175.20	175.20	175.68	175.20	175.20
GENERATION	GWH	Market Capacity	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
GENERATION	GWH	Nearman Creek	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
GENERATION	GWH	NextEra Crystal Lake 3 Wind Farm	41.39	41.39	41.39	41.50	41.39	41.39	41.39	41.50	41.39	41.39	41.39	41.50	41.39	41.39	41.39	41.50	41.39	41.39
GENERATION	GWH	PPA A	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
GENERATION	GWH	Prairie State Energy Campus	394.20	394.20	394.20	395.28	394.20	394.20	394.20	395.28	394.20	394.20	394.20	395.28	394.20	394.20	394.20	395.28	394.20	394.20
GENERATION	GWH	Sikeston	456.75	456.75	456.75	458.00	456.75	456.75	456.75	458.00	456.75	456.75	456.75	458.00	456.75	456.75	456.75	458.00	456.75	456.75
GENERATION	GWH	Wartsila Block x6	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
GENERATION	GWH	Wartsila Engine	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CAPACITY FACTOR	%	7FA Combined Cycle Fully Fired (25% ownership)																		
CAPACITY FACTOR	%	7FA Combined Cycle Fully Fired (25% ownership) :2022:700										18.00%	18.17%	18.25%	18.03%	18.11%	19.60%	19.92%	19.61%	19.13%
CAPACITY FACTOR	%	Ameresco/Columbia LFG	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%
CAPACITY FACTOR	%	Blue Grass Ridge	28.00%	28.00%	28.00%	28.00%	28.00%	28.00%	28.00%	28.00%	28.00%	28.00%	28.00%	28.00%	28.00%	28.00%	28.00%	28.00%	28.00%	28.00%
CAPACITY FACTOR	%	Columbia Energy Center	7.60%	7.61%	7.80%	7.86%	7.89%	7.95%	8.03%	7.88%	7.69%	1.83%	1.87%	1.90%	1.88%	1.91%	2.12%	2.17%	2.11%	2.04%
CAPACITY FACTOR	%	CWL Unit 5	0.00%	0.00%	0.00%															
CAPACITY FACTOR	%	CWL Unit 6	0.27%	0.27%	0.27%	0.40%	0.41%	0.42%	0.42%	0.43%	0.44%	0.04%	0.04%	0.04%	0.05%	0.05%	0.07%	0.07%	0.07%	0.06%
CAPACITY FACTOR	%	CWL Unit 7	2.15%	2.19%	2.24%															
CAPACITY FACTOR	%	CWL Unit 8	0.55%	0.53%	0.55%	0.64%	0.65%	0.65%	0.66%	0.66%	0.66%	0.08%	0.08%	0.09%	0.09%	0.09%	0.12%	0.13%	0.12%	0.11%

Table B-2 PF Gas Sensitivity
Columbia Water and Light
Burns & McDonnell Project No. 67546
2012 IRP

Resource Planning Model Output
Case: CWL 2

Data Item	Units	Description	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
CAPACITY FACTOR	%	Distributed Generation	0.24%	0.24%	0.25%	0.33%	0.34%	0.34%	0.35%	0.36%	0.38%	0.03%	0.03%	0.03%	0.03%	0.03%	0.05%	0.05%	0.05%	0.05%
CAPACITY FACTOR	%	Iatan 2	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
CAPACITY FACTOR	%	Market Capacity					0.00%	0.00%	0.00%	0.00%	0.00%								0.00%	0.00%
CAPACITY FACTOR	%	Nearman Creek																		
CAPACITY FACTOR	%	NextEra Crystal Lake 3 Wind Farm	45.00%	45.00%	45.00%	45.00%	45.00%	45.00%	45.00%	45.00%	45.00%	45.00%	45.00%	45.00%	45.00%	45.00%	45.00%	45.00%	45.00%	45.00%
CAPACITY FACTOR	%	PPA A																		
CAPACITY FACTOR	%	Prairie State Energy Campus	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%
CAPACITY FACTOR	%	Sikeston	79.00%	79.00%	79.00%	79.00%	79.00%	79.00%	79.00%	79.00%	79.00%	79.00%	79.00%	79.00%	79.00%	79.00%	79.00%	79.00%	79.00%	79.00%
CAPACITY FACTOR	%	Wartsila Block x6																		
CAPACITY FACTOR	%	Wartsila Engine																		
TOTAL O AND M COST	$000	7FA Combined Cycle Fully Fired (25% ownership)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL O AND M COST	$000	7FA Combined Cycle Fully Fired (25% ownership) :2022:700	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$2,060.12	$2,137.37	$2,216.55	$2,284.93	$2,367.65	$2,505.05	$2,606.85	$2,683.76	$2,758.18
TOTAL PURCHASE COST	$000	Ameresco/Columbia LFG	$3,405.89	$3,405.89	$3,405.89	$3,415.22	$3,405.89	$3,405.89	$3,405.89	$3,415.22	$3,405.89	$3,405.89	$3,405.89	$3,415.22	$3,405.89	$3,405.89	$3,405.89	$3,415.22	$3,405.89	$3,405.89
TOTAL PURCHASE COST	$000	Blue Grass Ridge	$1,004.42	$1,004.42	$1,004.42	$1,007.17	$1,004.42	$1,004.42	$1,004.42	$1,007.17	$1,004.42	$1,004.42	$1,004.42	$1,007.17	$1,004.42	$1,004.42	$1,004.42	$1,007.17	$1,004.42	$1,004.42
TOTAL O AND M COST	$000	Columbia Energy Center	$12,084.81	$12,387.15	$12,701.88	$13,021.38	$13,347.37	$14,030.78	$14,383.60	$14,739.58	$15,101.60	$15,297.00	$15,680.72	$16,073.90	$16,474.96	$16,887.74	$17,317.15	$17,647.18	$18,262.43	$18,898.77
TOTAL O AND M COST	$000	CWL Unit 5	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL O AND M COST	$000	CWL Unit 6	$1,778.82	$1,841.05	$1,905.97	$1,980.73	$2,050.67	$2,122.66	$2,197.08	$2,274.96	$2,355.50	$2,406.80	$2,491.33	$2,578.66	$2,669.00	$2,762.73	$2,861.31	$2,961.65	$3,065.01	$3,171.94
TOTAL O AND M COST	$000	CWL Unit 7	$1,893.30	$1,962.46	$2,033.93	$325.47	$336.86	$348.65	$360.85	$373.48	$386.56	$400.09	$414.09	$428.58	$443.58	$459.11	$475.18	$491.81	$509.02	$526.84
TOTAL O AND M COST	$000	CWL Unit 8	$441.68	$457.08	$473.14	$490.04	$507.22	$525.00	$543.41	$562.44	$582.12	$599.78	$620.80	$642.55	$665.04	$688.34	$712.59	$737.56	$763.33	$790.01
TOTAL O AND M COST	$000	Distributed Generation	$60.96	$63.15	$67.16	$92.25	$98.23	$102.30	$105.92	$114.97	$124.20	$8.95	$10.34	$11.01	$11.83	$13.36	$20.94	$22.08	$22.11	$21.86
TOTAL PURCHASE COST	$000	Iatan 2	$8,049.42	$8,235.00	$8,248.59	$8,386.67	$8,521.14	$8,661.30	$8,806.72	$8,968.17	$9,115.07	$9,278.01	$9,449.70	$9,639.27	$9,810.62	$10,001.58	$10,201.31	$10,422.80	$10,623.54	$10,847.80
TOTAL PURCHASE COST	$000	Market Capacity	$0.00	$0.00	$0.00	$0.00	$185.33	$402.10	$636.91	$925.73	$1,234.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$223.02	$606.80
TOTAL PURCHASE COST	$000	Nearman Creek	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL PURCHASE COST	$000	NextEra Crystal Lake 3 Wind Farm	$1,800.51	$1,841.90	$1,862.59	$1,867.70	$1,862.59	$1,862.59	$1,862.59	$1,867.70	$1,862.59	$1,862.59	$1,862.59	$1,867.70	$1,862.59	$1,862.59	$1,862.59	$1,867.70	$1,862.59	$1,862.59
TOTAL PURCHASE COST	$000	PPA A	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL PURCHASE COST	$000	Prairie State Energy Campus	$23,803.44	$25,262.06	$23,723.22	$22,971.09	$22,994.74	$23,476.78	$24,287.24	$25,097.02	$25,933.88	$26,811.01	$27,711.95	$28,696.49	$29,628.01	$30,644.88	$31,649.65	$32,744.04	$33,823.81	$34,995.23
TOTAL PURCHASE COST	$000	Sikeston	$24,617.16	$28,230.89	$28,958.47	$29,080.55	$28,772.06	$29,555.44	$30,589.88	$31,705.84	$32,768.65	$33,915.54	$35,102.59	$36,383.19	$37,602.77	$38,918.86	$40,281.03	$41,750.54	$43,150.05	$44,660.30
TOTAL O AND M COST	$000	Wartsila Block x6	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL O AND M COST	$000	Wartsila Engine	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
FIXED O AND M COST	$000	7FA Combined Cycle Fully Fired (25% ownership)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
FIXED O AND M COST	$000	7FA Combined Cycle Fully Fired (25% ownership) :2022:700	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$1,508.47	$1,561.26	$1,615.91	$1,672.46	$1,731.00	$1,791.59	$1,854.29	$1,919.19	$1,986.36
CAPACITY COST	$000	Ameresco/Columbia LFG	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
CAPACITY COST	$000	Blue Grass Ridge	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
FIXED O AND M COST	$000	Columbia Energy Center	$11,895.51	$12,192.89	$12,497.72	$12,810.16	$13,130.41	$13,806.72	$14,151.88	$14,505.68	$14,868.32	$15,240.03	$15,621.03	$16,011.56	$16,411.85	$16,822.14	$17,242.70	$17,567.87	$18,182.75	$18,819.14
FIXED O AND M COST	$000	CWL Unit 5	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
FIXED O AND M COST	$000	CWL Unit 6	$1,763.74	$1,825.47	$1,889.37	$1,955.49	$2,023.94	$2,094.77	$2,168.09	$2,243.97	$2,322.51	$2,403.80	$2,487.93	$2,575.01	$2,665.14	$2,758.42	$2,854.96	$2,954.89	$3,058.31	$3,165.35
FIXED O AND M COST	$000	CWL Unit 7	$1,763.66	$1,825.38	$1,889.27	$325.47	$336.86	$348.65	$360.85	$373.48	$386.56	$400.09	$414.09	$428.58	$443.58	$459.11	$475.18	$491.81	$509.02	$526.84
FIXED O AND M COST	$000	CWL Unit 8	$439.81	$455.20	$471.13	$487.62	$504.69	$522.35	$540.64	$559.56	$579.14	$599.41	$620.39	$642.11	$664.58	$687.84	$711.92	$736.83	$762.62	$789.31
FIXED O AND M COST	$000	Distributed Generation	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
CAPACITY COST	$000	Iatan 2	$5,050.00	$5,125.20	$5,014.40	$5,022.40	$5,022.40	$5,022.40	$5,022.40	$5,022.40	$5,022.40	$5,022.40	$5,022.40	$5,022.40	$5,022.40	$5,022.40	$5,022.40	$5,022.40	$5,022.40	$5,022.40
CAPACITY COST	$000	Market Capacity	$0.00	$0.00	$0.00	$0.00	$185.33	$402.10	$636.91	$925.73	$1,234.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$223.02	$606.80
CAPACITY COST	$000	Nearman Creek	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
CAPACITY COST	$000	NextEra Crystal Lake 3 Wind Farm	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
CAPACITY COST	$000	PPA A	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
CAPACITY COST	$000	Prairie State Energy Campus	$18,600.00	$19,625.00	$18,165.00	$17,200.00	$17,200.00	$17,524.36	$18,137.72	$18,772.54	$19,429.58	$20,109.61	$20,813.45	$21,541.92	$22,295.89	$23,076.24	$23,883.91	$24,719.85	$25,585.03	$26,480.51
CAPACITY COST	$000	Sikeston	$13,527.36	$14,464.55	$14,813.04	$14,612.40	$13,854.72	$14,116.00	$14,610.06	$15,121.41	$15,650.66	$16,198.43	$16,765.38	$17,352.17	$17,959.49	$18,588.07	$19,238.66	$19,912.01	$20,608.93	$21,330.24
FIXED O AND M COST	$000	Wartsila Block x6	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
FIXED O AND M COST	$000	Wartsila Engine	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
ANNUAL DEBT SERVICE	$000	7FA Combined Cycle Fully Fired (25% ownership) :2022:700										$9,981.25	$9,981.25	$9,981.25	$9,981.25	$9,981.25	$9,981.25	$9,981.25	$9,981.25	$9,981.25
VARIABLE O AND M COSTS	$/MWH	7FA Combined Cycle Fully Fired (25% ownership)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$/MWH	7FA Combined Cycle Fully Fired (25% ownership) :2022:700	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$3.67	$3.80	$3.93	$4.07	$4.21	$4.36	$4.51	$4.67	$4.83
ENERGY COSTS	$/MWH	Ameresco/Columbia LFG	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00
ENERGY COSTS	$/MWH	Blue Grass Ridge	$65.00	$65.00	$65.00	$65.00	$65.00	$65.00	$65.00	$65.00	$65.00	$65.00	$65.00	$65.00	$65.00	$65.00	$65.00	$65.00	$65.00	$65.00
VARIABLE O AND M COSTS	$/MWH	Columbia Energy Center	$1.97	$2.02	$2.07	$2.13	$2.18	$2.23	$2.29	$2.35	$2.40	$2.47	$2.53	$2.59	$2.65	$2.72	$2.79	$2.89	$2.99	$3.09
VARIABLE O AND M COSTS	$/MWH	CWL Unit 5	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$/MWH	CWL Unit 6	$51.62	$53.42	$55.29	$57.23	$59.23	$61.30	$63.45	$65.67	$67.97	$70.35	$72.81	$75.36	$77.99	$80.72	$83.55	$86.47	$89.50	$92.63
VARIABLE O AND M COSTS	$/MWH	CWL Unit 7	$31.35	$32.44	$33.58	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$/MWH	CWL Unit 8	$1.11	$1.15	$1.19	$1.23	$1.27	$1.32	$1.37	$1.41	$1.46	$1.51	$1.57	$1.62	$1.68	$1.74	$1.80	$1.86	$1.93	$1.99
VARIABLE O AND M COSTS	$/MWH	Distributed Generation	$228.06	$236.04	$244.30	$252.85	$261.70	$270.86	$280.34	$290.15	$300.31	$310.82	$321.70	$332.96	$344.61	$356.67	$369.15	$382.07	$395.45	$409.29
ENERGY COSTS	$/MWH	Iatan 2	$17.12	$17.75	$18.46	$19.15	$19.97	$20.77	$21.60	$22.46	$23.36	$24.29	$25.27	$26.28	$27.33	$28.42	$29.56	$30.74	$31.97	$33.25
ENERGY COSTS	$/MWH	Market Capacity	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
ENERGY COSTS	$/MWH	Nearman Creek	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
ENERGY COSTS	$/MWH	NextEra Crystal Lake 3 Wind Farm	$43.50	$44.50	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00
ENERGY COSTS	$/MWH	PPA A	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
ENERGY COSTS	$/MWH	Prairie State Energy Campus	$13.20	$14.30	$14.10	$14.60	$14.70	$15.10	$15.60	$16.00	$16.50	$17.00	$17.50	$18.10	$18.60	$19.20	$19.70	$20.30	$20.90	$21.60
ENERGY COSTS	$/MWH	Sikeston	$24.28	$30.14	$30.97	$31.59	$32.66	$33.80	$34.99	$36.21	$37.48	$38.79	$40.15	$41.55	$43.01	$44.51	$46.07	$47.68	$49.35	$51.08
VARIABLE O AND M COSTS	$/MWH	Wartsila Block x6	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$/MWH	Wartsila Engine	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$000	7FA Combined Cycle Fully Fired (25% ownership)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$000	7FA Combined Cycle Fully Fired (25% ownership) :2022:700	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$551.65	$576.10	$600.64	$612.47	$636.65	$713.46	$752.56	$764.57	$771.82
ENERGY COSTS	$000	Ameresco/Columbia LFG	$3,405.89	$3,405.89	$3,405.89	$3,415.22	$3,405.89	$3,405.89	$3,405.89	$3,415.22	$3,405.89	$3,405.89	$3,405.89	$3,415.22	$3,405.89	$3,405.89	$3,405.89	$3,415.22	$3,405.89	$3,405.89
ENERGY COSTS	$000	Blue Grass Ridge	$1,004.42	$1,004.42	$1,004.42	$1,007.17	$1,004.42	$1,004.42	$1,004.42	$1,007.17	$1,004.42	$1,004.42	$1,004.42	$1,007.17	$1,004.42	$1,004.42	$1,004.42	$1,007.17	$1,004.42	$1,004.42
VARIABLE O AND M COSTS	$000	Columbia Energy Center	$189.30	$194.26	$204.15	$211.22	$216.96	$224.06	$231.72	$233.90	$233.28	$56.97	$59.69	$62.34	$63.11	$65.60	$74.45	$78.31	$79.68	$79.63
VARIABLE O AND M COSTS	$000	CWL Unit 5	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$000	CWL Unit 6	$15.68	$15.56	$16.61	$25.24	$26.74	$27.89	$28.98	$30.98	$32.98	$3.00	$3.40	$3.65	$3.87	$4.31	$6.35	$6.76	$6.70	$6.59
VARIABLE O AND M COSTS	$000	CWL Unit 7	$129.64	$137.08	$144.65	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$000	CWL Unit 8	$1.87	$1.88	$2.01	$2.42	$2.53	$2.65	$2.77	$2.88	$2.97	$0.37	$0.41	$0.44	$0.46	$0.50	$0.67	$0.73	$0.71	$0.70
VARIABLE O AND M COSTS	$000	Distributed Generation	$60.96	$63.15	$67.16	$92.25	$98.23	$102.30	$105.92	$114.97	$124.20	$8.95	$10.34	$11.01	$11.83	$13.36	$20.94	$22.08	$22.11	$21.86
ENERGY COSTS	$000	Iatan 2	$2,999.42	$3,109.80	$3,234.19	$3,364.27	$3,498.74	$3,638.90	$3,784.32	$3,945.77	$4,092.67	$4,255.61	$4,427.30	$4,616.87	$4,788.22	$4,979.18	$5,178.91	$5,400.40	$5,601.14	$5,825.40
ENERGY COSTS	$000	Market Capacity	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
ENERGY COSTS	$000	Nearman Creek	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

Table B-2 PF Gas Sensitivity
Columbia Water and Light
Burns & McDonnell Project No. 67546
2012 IRP

Resource Planning Model Output
Case: CWL 2

Data Item	Units	Description	2013	2014	2015	2016	2017	2018	2019	2020	2021
ENERGY COSTS	$000	NextEra Crystal Lake 3 Wind Farm	$1,800.51	$1,841.90	$1,862.59	$1,867.70	$1,862.59	$1,862.59	$1,862.59	$1,867.70	$1,862.59
ENERGY COSTS	$000	PPA A	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
ENERGY COSTS	$000	Prairie State Energy Campus	$5,203.44	$5,637.06	$5,558.22	$5,771.09	$5,794.74	$5,952.42	$6,149.52	$6,324.48	$6,504.30
ENERGY COSTS	$000	Sikeston	$11,089.80	$13,766.34	$14,145.44	$14,468.15	$14,917.34	$15,439.44	$15,979.82	$16,584.43	$17,117.99
VARIABLE O AND M COSTS	$000	Wartsila Block x6	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$000	Wartsila Engine	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL FUEL COST	$000	7FA Combined Cycle Fully Fired (25% ownership)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL FUEL COST	$000	7FA Combined Cycle Fully Fired (25% ownership) :2022:700	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL FUEL COST	$000	Ameresco/Columbia LFG	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL FUEL COST	$000	Blue Grass Ridge	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL FUEL COST	$000	Columbia Energy Center	$8,814.84	$9,205.60	$9,664.78	$10,284.45	$10,857.22	$11,453.91	$11,962.63	$12,483.44	$13,072.88
TOTAL FUEL COST	$000	CWL Unit 5	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL FUEL COST	$000	CWL Unit 6	$38.14	$39.81	$42.00	$64.55	$69.50	$73.52	$76.50	$83.70	$92.65
TOTAL FUEL COST	$000	CWL Unit 7	$315.67	$329.26	$339.72	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL FUEL COST	$000	CWL Unit 8	$167.25	$169.20	$179.17	$222.26	$237.20	$251.22	$262.71	$279.61	$300.55
TOTAL FUEL COST	$000	Distributed Generation	$60.44	$62.61	$56.61	$91.43	$97.35	$101.40	$104.99	$113.94	$123.06
TOTAL FUEL COST	$000	Iatan 2	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL FUEL COST	$000	Market Capacity	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL FUEL COST	$000	Nearman Creek	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL FUEL COST	$000	NextEra Crystal Lake 3 Wind Farm	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL FUEL COST	$000	PPA A	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL FUEL COST	$000	Prairie State Energy Campus	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL FUEL COST	$000	Sikeston	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL FUEL COST	$000	Wartsila Block x6	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL FUEL COST	$000	Wartsila Engine	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL VARIABLE COST	$/MWH	7FA Combined Cycle Fully Fired (25% ownership)									
TOTAL VARIABLE COST	$/MWH	7FA Combined Cycle Fully Fired (25% ownership) :2022:700									
TOTAL ENERGY COSTS	$/MWH	Ameresco/Columbia LFG	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00
TOTAL ENERGY COSTS	$/MWH	Blue Grass Ridge	$65.00	$65.00	$65.00	$65.00	$65.00	$65.00	$65.00	$65.00	$65.00
TOTAL VARIABLE COST	$/MWH	Columbia Energy Center	$93.88	$97.89	$100.25	$105.62	$111.21	$116.39	$120.46	$127.57	$137.17
TOTAL VARIABLE COST	$/MWH	CWL Unit 5									
TOTAL VARIABLE COST	$/MWH	CWL Unit 6	$182.18	$189.92	$195.12	$203.61	$213.20	$222.90	$230.91	$243.08	$258.89
TOTAL VARIABLE COST	$/MWH	CWL Unit 7	$107.72	$110.37	$112.43						
TOTAL VARIABLE COST	$/MWH	CWL Unit 8	$100.64	$104.91	$107.43	$114.60	$120.62	$126.44	$130.96	$138.77	$149.35
TOTAL VARIABLE COST	$/MWH	Distributed Generation	$454.14	$470.09	$486.59	$503.45	$521.06	$539.32	$558.20	$577.68	$597.86
TOTAL ENERGY COSTS	$/MWH	Iatan 2	$17.12	$17.75	$18.46	$19.15	$19.97	$20.77	$21.60	$22.46	$23.36
TOTAL ENERGY COSTS	$/MWH	Market Capacity									
TOTAL ENERGY COSTS	$/MWH	Nearman Creek									
TOTAL ENERGY COSTS	$/MWH	NextEra Crystal Lake 3 Wind Farm	$43.50	$44.50	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00
TOTAL ENERGY COSTS	$/MWH	PPA A									
TOTAL ENERGY COSTS	$/MWH	Prairie State Energy Campus	$13.20	$14.30	$14.10	$14.60	$14.70	$15.10	$15.60	$16.00	$16.50
TOTAL ENERGY COSTS	$/MWH	Sikeston	$24.28	$30.14	$30.97	$31.59	$32.66	$33.80	$34.99	$36.21	$37.48
TOTAL VARIABLE COST	$/MWH	Wartsila Block x6									
TOTAL VARIABLE COST	$/MWH	Wartsila Engine									
SYSTEM EFFLUENT EXPENSE	$000	NOx	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
SYSTEM EFFLUENT EXPENSE	$000	CO2	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
SYSTEM EFFLUENT EXPENSE	$000	SO2	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
SYSTEM EFFLUENT EXPENSE	$000	Hg	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
SYSTEM EFFLUENT EXPENSE	$000	CO	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
SUMMARY OF COSTS											
TOTAL FIXED COSTS	$000		$15,863	$16,299	$16,747	$15,579	$15,996	$16,772	$17,221	$17,683	$18,157
TOTAL VARIABLE (EXCL. FUEL) COSTS	$000		$7,960	$9,206	$10,342	$11,680	$13,567	$15,687	$17,897	$20,344	$23,540
TOTAL FUEL COSTS	$000		$9,397	$9,806	$10,292	$10,563	$11,261	$11,880	$12,407	$12,961	$13,589
TOTAL DEBT SERVICE COSTS	$000		$0	$0	$0	$0	$0	$0	$0	$0	$0
TOTAL PURCHASE COSTS	$000		$62,681	$67,980	$67,203	$66,728	$66,746	$68,369	$70,594	$72,987	$75,325
TOTAL COSTS	$000		$95,900	$103,292	$104,585	$104,650	$107,570	$112,708	$118,119	$123,975	$130,610

Data Item	Units	Description	2022	2023	2024	2025	2026	2027	2028	2029	2030
ENERGY COSTS	$000	NextEra Crystal Lake 3 Wind Farm	$1,862.59	$1,862.59	$1,867.70	$1,862.59	$1,862.59	$1,862.59	$1,867.70	$1,862.59	$1,862.59
ENERGY COSTS	$000	PPA A	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
ENERGY COSTS	$000	Prairie State Energy Campus	$6,701.40	$6,898.50	$7,154.57	$7,332.12	$7,568.64	$7,765.74	$8,024.18	$8,238.78	$8,514.72
ENERGY COSTS	$000	Sikeston	$17,717.11	$18,337.21	$19,031.02	$19,643.28	$20,330.80	$21,042.37	$21,838.53	$22,541.12	$23,330.06
VARIABLE O AND M COSTS	$000	Wartsila Block x6	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$000	Wartsila Engine	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL FUEL COST	$000	7FA Combined Cycle Fully Fired (25% ownership)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL FUEL COST	$000	7FA Combined Cycle Fully Fired (25% ownership) :2022:700	$12,319.46	$13,014.71	$13,623.54	$14,208.79	$14,983.20	$16,544.07	$17,046.88	$17,226.91	$17,719.61
TOTAL FUEL COST	$000	Ameresco/Columbia LFG	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL FUEL COST	$000	Blue Grass Ridge	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL FUEL COST	$000	Columbia Energy Center	$3,273.88	$3,506.51	$3,712.50	$3,887.56	$4,140.13	$4,679.82	$4,872.94	$4,870.45	$4,959.25
TOTAL FUEL COST	$000	CWL Unit 5	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL FUEL COST	$000	CWL Unit 6	$8.33	$9.56	$10.28	$11.22	$12.71	$18.63	$19.35	$19.15	$19.21
TOTAL FUEL COST	$000	CWL Unit 7	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL FUEL COST	$000	CWL Unit 8	$37.22	$41.73	$45.16	$48.54	$53.82	$71.57	$75.36	$73.70	$73.58
TOTAL FUEL COST	$000	Distributed Generation	$8.86	$10.23	$10.89	$11.70	$13.21	$20.74	$21.85	$21.89	$21.64
TOTAL FUEL COST	$000	Iatan 2	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL FUEL COST	$000	Market Capacity	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL FUEL COST	$000	Nearman Creek	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL FUEL COST	$000	NextEra Crystal Lake 3 Wind Farm	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL FUEL COST	$000	PPA A	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL FUEL COST	$000	Prairie State Energy Campus	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL FUEL COST	$000	Sikeston	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL FUEL COST	$000	Wartsila Block x6	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL FUEL COST	$000	Wartsila Engine	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL VARIABLE COST	$/MWH	7FA Combined Cycle Fully Fired (25% ownership)									
TOTAL VARIABLE COST	$/MWH	7FA Combined Cycle Fully Fired (25% ownership) :2022:700	$85.57	$89.55	$93.04	$98.40	$103.26	$105.36	$106.63	$109.80	$115.71
TOTAL ENERGY COSTS	$/MWH	Ameresco/Columbia LFG	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00
TOTAL ENERGY COSTS	$/MWH	Blue Grass Ridge	$65.00	$65.00	$65.00	$65.00	$65.00	$65.00	$65.00	$65.00	$65.00
TOTAL VARIABLE COST	$/MWH	Columbia Energy Center	$144.12	$150.95	$156.81	$166.17	$174.45	$178.10	$180.24	$185.61	$195.66
TOTAL VARIABLE COST	$/MWH	CWL Unit 5									
TOTAL VARIABLE COST	$/MWH	CWL Unit 6	$265.87	$277.65	$287.61	$304.41	$318.57	$328.66	$333.86	$345.37	$362.71
TOTAL VARIABLE COST	$/MWH	CWL Unit 7									
TOTAL VARIABLE COST	$/MWH	CWL Unit 8	$154.51	$162.03	$168.02	$179.04	$188.09	$192.92	$195.12	$201.44	$212.56
TOTAL VARIABLE COST	$/MWH	Distributed Generation	$618.44	$639.94	$662.34	$685.34	$709.29	$734.73	$760.10	$786.94	$814.44
TOTAL ENERGY COSTS	$/MWH	Iatan 2	$24.29	$25.27	$26.28	$27.33	$28.42	$29.56	$30.74	$31.97	$33.25
TOTAL ENERGY COSTS	$/MWH	Market Capacity									
TOTAL ENERGY COSTS	$/MWH	Nearman Creek									
TOTAL ENERGY COSTS	$/MWH	NextEra Crystal Lake 3 Wind Farm	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00
TOTAL ENERGY COSTS	$/MWH	PPA A									
TOTAL ENERGY COSTS	$/MWH	Prairie State Energy Campus	$17.00	$17.50	$18.10	$18.60	$19.20	$19.70	$20.30	$20.90	$21.60
TOTAL ENERGY COSTS	$/MWH	Sikeston	$38.79	$40.15	$41.55	$43.01	$44.51	$46.07	$47.68	$49.35	$51.08
TOTAL VARIABLE COST	$/MWH	Wartsila Block x6									
TOTAL VARIABLE COST	$/MWH	Wartsila Engine									
SYSTEM EFFLUENT EXPENSE	$000	NOx	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
SYSTEM EFFLUENT EXPENSE	$000	CO2	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
SYSTEM EFFLUENT EXPENSE	$000	SO2	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
SYSTEM EFFLUENT EXPENSE	$000	Hg	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
SYSTEM EFFLUENT EXPENSE	$000	CO	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
SUMMARY OF COSTS											
TOTAL FIXED COSTS	$000		$20,152	$20,705	$21,273	$21,858	$22,459	$23,076	$23,606	$24,432	$25,287
TOTAL VARIABLE (EXCL. FUEL) COSTS	$000		$18,390	$21,145	$23,984	$27,621	$30,146	$31,866	$34,312	$37,793	$41,963
TOTAL FUEL COSTS	$000		$15,648	$16,583	$17,402	$18,168	$19,203	$21,335	$22,036	$22,212	$22,793
TOTAL DEBT SERVICE COSTS	$000		$9,981	$9,981	$9,981	$9,981	$9,981	$9,981	$9,981	$9,981	$9,981
TOTAL PURCHASE COSTS	$000		$76,277	$78,537	$81,009	$83,314	$85,838	$88,405	$91,207	$94,093	$97,383
TOTAL COSTS	$000		$140,448	$146,951	$153,650	$160,842	$167,627	$174,564	$181,143	$188,511	$197,408

NPV @ 4.0% ($000): $1,687,432

Table B-3 CWL CF Base
Columbia Water and Light
Burns & McDonnell Project No. 67546
2012 IRP

Resource Planning Model Output
Case: CWL 4

Data Item	Units	Description	2013	2014	2015	2016 2017	2018	2019	2020	2021	2022	2023	2024	2025		2026	2027	2028	2029	2030
ENERGY REQUIREMENTS	GWH		1251.00	1278.00	1304.00	1329.00	1358.00	1393.00	1427.00	1461.00	1495.00	1532.00	1569.00	1607.00	1645.00	1663.00	1695.00	1727.00	1760.00	1792.00
PEAK DEMAND	MW		285.00	289.00	294.00	300.00	306.00	312.00	318.00	325.00	332.00	338.00	345.00	353.00	360.00	366.00	373.00	381.00	387.00	394.00
REQUIRED RESERVES	MW		46.40	47.05	47.86	48.84	49.82	50.79	51.77	52.91	54.05	55.03	56.17	57.47	58.61	59.58	60.72	62.03	63.00	64.14
TOTAL CAPACITY RESPONSIBILITY	MW		331.40	336.05	341.86	348.84	355.82	362.79	369.77	377.91	386.05	393.03	401.17	410.47	418.61	425.58	433.72	443.03	450.00	458.14
TOTAL FIRM RESOURCES	MW		388.17	388.17	388.17	349.67	355.85	362.82	369.80	377.94	386.08	393.06	401.20	410.50	418.64	425.62	433.76	443.06	450.04	458.18
RESERVE SURPLUS/(DEFICIT)	MW		56.77	52.12	46.31	0.83	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.04	0.04	0.04	0.04	0.04	0.04	0.04
RESERVE MARGIN	%		36%	34%	32%	17%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%
DUMP ENERGY	GWH		127.82	121.26	114.14	112.98	107.84	101.34	90.07	85.54	80.70	78.01	74.60	73.46	74.12	73.84	67.21	65.23	65.70	67.82
ECONOMY INTERCHANGE PURCHASE ENERGY	GWH		101.57	120.22	133.88	162.11	187.85	212.86	215.82	234.78	259.90	289.87	310.81	342.63	387.12	403.22	413.40	436.44	477.52	517.01
ECONOMY INTERCHANGE SALES ENERGY	GWH		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ECONOMY INTERCHANGE PURCHASE COST	$000		$4,557.99	$5,491.65	$6,266.01	$7,804.70	$9,353.02	$10,972.75	$11,329.12	$12,590.88	$14,372.38	$16,883.67	$18,513.82	$21,141.61	$24,679.58	$26,990.45	$28,602.28	$30,948.09	$34,340.22	$38,382.23
ECONOMY INTERCHANGE SALES COST	$000		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
EMERGENCY ENERGY	GWH		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EMERGENCY COST	$000		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TRANSACTION PURCHASE COST	$000		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TRANSACTION SALES COST	$000		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
FIRM CAPACITY	MW	7FA Combined Cycle Fully Fired (25% ownership)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FIRM CAPACITY	MW	Ameresco/Columbia LFG	7.20	7.20	7.20	7.20	7.20	7.20	7.20	7.20	7.20	7.20	7.20	7.20	7.20	7.20	7.20	7.20	7.20	7.20
FIRM CAPACITY	MW	Blue Grass Ridge	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93
FIRM CAPACITY	MW	Columbia Energy Center	144.00	144.00	144.00	144.00	144.00	144.00	144.00	144.00	144.00	144.00	144.00	144.00	144.00	144.00	144.00	144.00	144.00	144.00
FIRM CAPACITY	MW	CWL Unit 5	16.50	16.50	16.50	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FIRM CAPACITY	MW	CWL Unit 6	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50
FIRM CAPACITY	MW	CWL Unit 7	22.00	22.00	22.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FIRM CAPACITY	MW	CWL Unit 8	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00
FIRM CAPACITY	MW	Distributed Generation	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50
FIRM CAPACITY	MW	Iatan 2	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00
FIRM CAPACITY	MW	Market Capacity	0.00	0.00	0.00	0.00	6.18	13.16	1.93	0.97	0.01	6.99	6.03	15.33	23.47	30.45	38.59	47.90	54.87	63.01
FIRM CAPACITY	MW	Nearman Creek	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FIRM CAPACITY	MW	NextEra Crystal Lake 3 Wind Farm	1.54	1.54	1.54	1.54	1.54	1.54	1.54	1.54	1.54	1.54	1.54	1.54	1.54	1.54	1.54	1.54	1.54	1.54
FIRM CAPACITY	MW	PPA A	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FIRM CAPACITY	MW	Prairie State Energy Campus	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00
FIRM CAPACITY	MW	Sikeston	66.00	66.00	66.00	66.00	66.00	66.00	66.00	66.00	66.00	66.00	66.00	66.00	66.00	66.00	66.00	66.00	66.00	66.00
FIRM CAPACITY	MW	Wartsila Block x6	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FIRM CAPACITY	MW	Wartsila Block x6 .2019:700	0.00	0.00	0.00	0.00	0.00	0.00	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10
FIRM CAPACITY	MW	Wartsila Engine	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FIRM CAPACITY	MW	Wartsila Engine .2019:699	0.00	0.00	0.00	0.00	0.00	0.00	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10
FIRM CAPACITY	MW	Wartsila Engine .2020:698	0.00	0.00	0.00	0.00	0.00	0.00	0.00	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10
FIRM CAPACITY	MW	Wartsila Engine .2021:697	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10
FIRM CAPACITY	MW	Wartsila Engine .2023:696	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10
MAXIMUM CAPACITY	MW	7FA Combined Cycle Fully Fired (25% ownership)	381.50	381.50	381.50	381.50	381.50	381.50	381.50	381.50	381.50	381.50	381.50	381.50	381.50	381.50	381.50	381.50	381.50	381.50
MAXIMUM CAPACITY	MW	Ameresco/Columbia LFG	7.20	7.20	7.20	7.20	7.20	7.20	7.20	7.20	7.20	7.20	7.20	7.20	7.20	7.20	7.20	7.20	7.20	7.20
MAXIMUM CAPACITY	MW	Blue Grass Ridge	6.30	6.30	6.30	6.30	6.30	6.30	6.30	6.30	6.30	6.30	6.30	6.30	6.30	6.30	6.30	6.30	6.30	6.30
MAXIMUM CAPACITY	MW	Columbia Energy Center	144.00	144.00	144.00	144.00	144.00	144.00	144.00	144.00	144.00	144.00	144.00	144.00	144.00	144.00	144.00	144.00	144.00	144.00
MAXIMUM CAPACITY	MW	CWL Unit 5	16.50	16.50	16.50	16.50	16.50	16.50	16.50	16.50	16.50	16.50	16.50	16.50	16.50	16.50	16.50	16.50	16.50	16.50
MAXIMUM CAPACITY	MW	CWL Unit 6	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50
MAXIMUM CAPACITY	MW	CWL Unit 7	22.00	22.00	22.00	22.00	22.00	22.00	22.00	22.00	22.00	22.00	22.00	22.00	22.00	22.00	22.00	22.00	22.00	22.00
MAXIMUM CAPACITY	MW	CWL Unit 8	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00
MAXIMUM CAPACITY	MW	Distributed Generation	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50
MAXIMUM CAPACITY	MW	Iatan 2	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00
MAXIMUM CAPACITY	MW	Market Capacity	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
MAXIMUM CAPACITY	MW	Nearman Creek	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00
MAXIMUM CAPACITY	MW	NextEra Crystal Lake 3 Wind Farm	10.50	10.50	10.50	10.50	10.50	10.50	10.50	10.50	10.50	10.50	10.50	10.50	10.50	10.50	10.50	10.50	10.50	10.50
MAXIMUM CAPACITY	MW	PPA A	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00
MAXIMUM CAPACITY	MW	Prairie State Energy Campus	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00
MAXIMUM CAPACITY	MW	Sikeston	66.00	66.00	66.00	66.00	66.00	66.00	66.00	66.00	66.00	66.00	66.00	66.00	66.00	66.00	66.00	66.00	66.00	66.00
MAXIMUM CAPACITY	MW	Wartsila Block x6	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10
MAXIMUM CAPACITY	MW	Wartsila Block x6 .2019:700	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10
MAXIMUM CAPACITY	MW	Wartsila Engine	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10
MAXIMUM CAPACITY	MW	Wartsila Engine .2019:699	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10
MAXIMUM CAPACITY	MW	Wartsila Engine .2020:698	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10
MAXIMUM CAPACITY	MW	Wartsila Engine .2021:697	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10
MAXIMUM CAPACITY	MW	Wartsila Engine .2023:696	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10
GENERATION	GWH	7FA Combined Cycle Fully Fired (25% ownership)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
GENERATION	GWH	Ameresco/ Columbia LFG	56.76	56.76	56.76	56.92	56.76	56.76	56.76	56.92	56.76	56.76	56.76	56.92	56.76	56.76	56.76	56.92	56.76	56.76
GENERATION	GWH	Blue Grass Ridge	15.45	15.45	15.45	15.49	15.45	15.45	15.45	15.49	15.45	15.45	15.45	15.49	15.45	15.45	15.45	15.49	15.45	15.45
GENERATION	GWH	Columbia Energy Center	133.07	134.97	139.98	133.57	134.82	138.27	95.89	78.32	63.91	66.33	57.34	58.25	57.31	58.31	63.88	65.41	63.23	60.92
GENERATION	GWH	CWL Unit 5	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
GENERATION	GWH	CWL Unit 6	0.32	0.30	0.31	0.46	0.45	0.45	0.27	0.21	0.17	0.19	0.19	0.20	0.19	0.21	0.25	0.26	0.24	0.22
GENERATION	GWH	CWL Unit 7	0.82	0.79	0.82	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
GENERATION	GWH	CWL Unit 8	3.03	3.00	3.16	2.67	2.67	2.73	1.66	1.27	1.00	1.09	1.01	1.05	1.03	1.08	1.27	1.31	1.22	1.14
GENERATION	GWH	Distributed Generation	0.25	0.23	0.23	0.30	0.29	0.28	0.16	0.13	0.11	0.12	0.13	0.13	0.13	0.14	0.18	0.18	0.17	0.16
GENERATION	GWH	Iatan 2	175.20	175.20	175.20	175.68	175.20	175.20	175.20	175.68	175.20	175.20	175.20	175.68	175.20	175.20	175.20	175.68	175.20	175.20
GENERATION	GWH	Market Capacity	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
GENERATION	GWH	Nearman Creek	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
GENERATION	GWH	NextEra Crystal Lake 3 Wind Farm	41.39	41.39	41.39	41.50	41.39	41.39	41.39	41.50	41.39	41.39	41.39	41.50	41.39	41.39	41.39	41.50	41.39	41.39
GENERATION	GWH	PPA A	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
GENERATION	GWH	Prairie State Energy Campus	394.20	394.20	394.20	395.28	394.20	394.20	394.20	395.28	394.20	394.20	394.20	395.28	394.20	394.20	394.20	395.28	394.20	394.20
GENERATION	GWH	Sikeston	456.75	456.75	456.75	458.00	456.75	456.75	456.75	458.00	456.75	456.75	456.75	458.00	456.75	456.75	456.75	458.00	456.75	456.75
GENERATION	GWH	Wartsila Block x6	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Table B-3 CWL CF Base
Columbia Water and Light
Burns & McDonnell Project No. 67546
2012 IRP

Resource Planning Model Output
Case: CWL 4

Data Item	Units	Description	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
GENERATION	GWH	Wartsila Block x6 :2019:700	0.00	0.00	0.00	0.00	0.00	0.00	28.54	23.69	19.55	19.94	16.97	17.10	16.85	16.96	18.32	18.65	18.26	17.77
GENERATION	GWH	Wartsila Engine	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
GENERATION	GWH	Wartsila Engine :2019:699	0.00	0.00	0.00	0.00	0.00	0.00	34.97	29.38	24.40	24.83	21.07	21.21	20.91	21.02	22.67	23.06	22.63	22.07
GENERATION	GWH	Wartsila Engine :2020:698	0.00	0.00	0.00	0.00	0.00	0.00	0.00	35.89	30.17	30.64	26.04	26.21	25.86	25.97	27.90	28.35	27.90	27.28
GENERATION	GWH	Wartsila Engine :2021:697	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	36.73	37.24	31.87	32.10	31.70	31.80	33.96	34.48	34.02	33.37
GENERATION	GWH	Wartsila Engine :2023:696	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	38.42	38.70	38.28	38.37	40.63	41.20	40.76	40.11
CAPACITY FACTOR	%	7FA Combined Cycle Fully Fired (25% ownership)																		
CAPACITY FACTOR	%	Ameresco/Columbia LFG	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%
CAPACITY FACTOR	%	Blue Grass Ridge	28.00%	28.00%	28.00%	28.00%	28.00%	28.00%	28.00%	28.00%	28.00%	28.00%	28.00%	28.00%	28.00%	28.00%	28.00%	28.00%	28.00%	28.00%
CAPACITY FACTOR	%	Columbia Energy Center	10.55%	10.70%	11.10%	10.56%	10.69%	10.96%	7.60%	6.19%	5.07%	5.26%	4.55%	4.60%	4.54%	4.62%	5.06%	5.17%	5.01%	4.83%
CAPACITY FACTOR	%	CWL Unit 5	0.00%	0.00%	0.00%															
CAPACITY FACTOR	%	CWL Unit 6	0.30%	0.28%	0.28%	0.42%	0.41%	0.41%	0.24%	0.19%	0.16%	0.17%	0.17%	0.18%	0.18%	0.19%	0.23%	0.24%	0.22%	0.21%
CAPACITY FACTOR	%	CWL Unit 7	0.42%	0.41%	0.42%															
CAPACITY FACTOR	%	CWL Unit 8	0.99%	0.98%	1.03%	0.87%	0.87%	0.89%	0.54%	0.41%	0.33%	0.36%	0.33%	0.34%	0.33%	0.35%	0.41%	0.43%	0.40%	0.37%
CAPACITY FACTOR	%	Distributed Generation	0.23%	0.21%	0.21%	0.27%	0.26%	0.26%	0.15%	0.12%	0.10%	0.11%	0.12%	0.12%	0.12%	0.13%	0.15%	0.17%	0.15%	0.15%
CAPACITY FACTOR	%	Iatan 2	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
CAPACITY FACTOR	%	Market Capacity					0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
CAPACITY FACTOR	%	Nearman Creek																		
CAPACITY FACTOR	%	NextEra Crystal Lake 3 Wind Farm	45.00%	45.00%	45.00%	45.00%	45.00%	45.00%	45.00%	45.00%	45.00%	45.00%	45.00%	45.00%	45.00%	45.00%	45.00%	45.00%	45.00%	45.00%
CAPACITY FACTOR	%	PPA A																		
CAPACITY FACTOR	%	Prairie State Energy Campus	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%
CAPACITY FACTOR	%	Sikeston	79.00%	79.00%	79.00%	79.00%	79.00%	79.00%	79.00%	79.00%	79.00%	79.00%	79.00%	79.00%	79.00%	79.00%	79.00%	79.00%	79.00%	79.00%
CAPACITY FACTOR	%	Wartsila Block x6																		
CAPACITY FACTOR	%	Wartsila Block x6 :2019:700							35.80%	29.63%	24.52%	25.01%	21.29%	21.39%	21.13%	21.28%	22.99%	23.33%	22.81%	22.30%
CAPACITY FACTOR	%	Wartsila Engine																		
CAPACITY FACTOR	%	Wartsila Engine :2019:699							43.87%	36.75%	30.61%	31.15%	26.43%	26.54%	26.23%	26.37%	28.44%	28.85%	28.39%	27.69%
CAPACITY FACTOR	%	Wartsila Engine :2020:698								44.90%	37.85%	38.44%	32.66%	32.79%	32.43%	32.57%	35.00%	35.47%	35.00%	34.22%
CAPACITY FACTOR	%	Wartsila Engine :2021:697									46.07%	46.71%	39.98%	40.16%	39.77%	39.89%	42.60%	43.14%	42.68%	41.86%
CAPACITY FACTOR	%	Wartsila Engine :2023:696											48.19%	48.42%	48.02%	48.13%	50.97%	51.55%	51.13%	50.32%
TOTAL O AND M COST	$000	7FA Combined Cycle Fully Fired (25% ownership)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL PURCHASE COST	$000	Ameresco/Columbia LFG	$3,405.89	$3,405.89	$3,405.89	$3,415.22	$3,405.89	$3,405.89	$3,405.89	$3,415.22	$3,405.89	$3,405.89	$3,405.89	$3,415.22	$3,405.89	$3,405.89	$3,405.89	$3,415.22	$3,405.89	$3,405.89
TOTAL PURCHASE COST	$000	Blue Grass Ridge	$1,004.42	$1,004.42	$1,004.42	$1,007.17	$1,004.42	$1,004.42	$1,004.42	$1,007.17	$1,004.42	$1,004.42	$1,004.42	$1,007.17	$1,004.42	$1,004.42	$1,004.42	$1,007.17	$1,004.42	$1,004.42
TOTAL O AND M COST	$000	Columbia Energy Center	$12,158.17	$12,465.95	$12,788.01	$13,094.07	$13,424.15	$14,115.49	$14,371.37	$14,689.43	$15,022.02	$15,403.53	$15,785.91	$16,162.41	$16,563.98	$16,980.80	$17,420.85	$17,756.67	$18,371.65	$19,007.52
TOTAL O AND M COST	$000	CWL Unit 5	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL O AND M COST	$000	CWL Unit 6	$1,780.47	$1,841.77	$1,906.60	$1,981.77	$2,050.63	$2,122.50	$2,185.09	$2,257.54	$2,334.09	$2,417.11	$2,501.49	$2,589.71	$2,680.22	$2,775.11	$2,875.81	$2,977.33	$3,079.69	$3,186.18
TOTAL O AND M COST	$000	CWL Unit 7	$1,789.24	$1,850.86	$1,916.75	$325.47	$336.86	$348.65	$360.85	$373.48	$386.56	$400.09	$414.09	$428.58	$443.58	$459.11	$475.18	$491.81	$509.02	$526.84
TOTAL O AND M COST	$000	CWL Unit 8	$443.17	$458.66	$474.90	$490.91	$508.09	$525.95	$542.90	$561.35	$580.61	$601.07	$621.97	$643.81	$666.30	$689.72	$714.20	$739.28	$764.97	$791.59
TOTAL O AND M COST	$000	Distributed Generation	$56.39	$54.02	$55.88	$74.77	$74.82	$76.06	$45.48	$37.08	$33.17	$38.41	$40.67	$43.83	$45.97	$51.32	$64.90	$70.20	$67.08	$66.09
TOTAL PURCHASE COST	$000	Iatan 2	$8,049.42	$8,235.00	$8,248.59	$8,386.67	$8,521.14	$8,661.30	$8,806.72	$8,968.17	$9,115.07	$9,278.01	$9,449.70	$9,639.27	$9,810.62	$10,001.58	$10,201.31	$10,422.80	$10,623.54	$10,847.80
TOTAL PURCHASE COST	$000	Market Capacity	$0.00	$0.00	$0.00	$0.00	$185.33	$402.10	$61.14	$31.85	$0.45	$245.19	$218.94	$576.15	$912.87	$1,225.66	$1,607.67	$2,065.05	$2,448.70	$2,910.38
TOTAL PURCHASE COST	$000	Nearman Creek	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL PURCHASE COST	$000	NextEra Crystal Lake 3 Wind Farm	$1,800.51	$1,841.90	$1,862.59	$1,867.70	$1,862.59	$1,862.59	$1,862.59	$1,867.70	$1,862.59	$1,862.59	$1,862.59	$1,867.70	$1,862.59	$1,862.59	$1,862.59	$1,867.70	$1,862.59	$1,862.59
TOTAL PURCHASE COST	$000	PPA A	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL PURCHASE COST	$000	Prairie State Energy Campus	$23,803.44	$25,262.06	$23,723.22	$22,971.09	$22,994.74	$23,476.78	$24,287.24	$25,097.02	$25,933.88	$26,811.01	$27,711.95	$28,696.49	$29,628.01	$30,644.88	$31,649.65	$32,744.04	$33,823.81	$34,995.23
TOTAL PURCHASE COST	$000	Sikeston	$24,617.16	$28,230.89	$28,958.47	$29,080.55	$28,772.06	$29,555.44	$30,589.88	$31,705.84	$32,768.65	$33,915.54	$35,102.59	$36,383.19	$37,602.77	$38,918.86	$40,281.03	$41,750.54	$43,150.05	$44,660.30
TOTAL O AND M COST	$000	Wartsila Block x6	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL O AND M COST	$000	Wartsila Block x6 :2019:700	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$586.22	$567.73	$553.20	$575.90	$569.66	$590.77	$609.03	$631.52	$667.51	$694.34	$714.37	$733.86
TOTAL O AND M COST	$000	Wartsila Engine	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL O AND M COST	$000	Wartsila Engine :2019:699	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$419.60	$389.33	$361.56	$377.92	$357.66	$371.51	$381.59	$396.08	$426.79	$445.83	$456.75	$466.39
TOTAL O AND M COST	$000	Wartsila Engine :2020:698	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$441.65	$409.54	$427.95	$401.89	$417.59	$428.79	$444.89	$480.23	$501.84	$514.44	$525.41
TOTAL O AND M COST	$000	Wartsila Engine :2021:697	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$464.06	$484.68	$453.87	$471.84	$484.56	$502.52	$542.18	$566.64	$581.43	$594.38
TOTAL O AND M COST	$000	Wartsila Engine :2023:696	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$512.17	$532.73	$547.35	$567.38	$610.37	$637.75	$655.19	$670.83
FIXED O AND M COST	$000	7FA Combined Cycle Fully Fired (25% ownership)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
CAPACITY COST	$000	Ameresco/Columbia LFG	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
CAPACITY COST	$000	Blue Grass Ridge	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
FIXED O AND M COST	$000	Columbia Energy Center	$11,895.51	$12,192.89	$12,497.72	$12,810.16	$13,130.41	$13,806.72	$14,151.86	$14,505.68	$14,868.32	$15,240.03	$15,621.03	$16,011.56	$16,411.85	$16,822.14	$17,242.70	$17,567.87	$18,182.75	$18,819.14
FIXED O AND M COST	$000	CWL Unit 5	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
FIXED O AND M COST	$000	CWL Unit 6	$1,763.74	$1,825.47	$1,889.37	$1,955.49	$2,023.94	$2,094.77	$2,168.09	$2,243.97	$2,322.51	$2,403.80	$2,487.93	$2,575.01	$2,665.14	$2,758.42	$2,854.96	$2,954.89	$3,058.31	$3,165.35
FIXED O AND M COST	$000	CWL Unit 7	$1,763.66	$1,825.38	$1,889.27	$325.47	$336.86	$348.65	$360.85	$373.48	$386.56	$400.09	$414.09	$428.58	$443.58	$459.11	$475.18	$491.81	$509.02	$526.84
FIXED O AND M COST	$000	CWL Unit 8	$439.81	$455.20	$471.13	$487.62	$504.69	$522.35	$540.64	$559.56	$579.14	$599.41	$620.39	$642.11	$664.58	$687.84	$711.92	$736.83	$762.62	$789.31
FIXED O AND M COST	$000	Distributed Generation	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
CAPACITY COST	$000	Iatan 2	$5,050.00	$5,125.20	$5,014.40	$5,022.40	$5,022.40	$5,022.40	$5,022.40	$5,022.40	$5,022.40	$5,022.40	$5,022.40	$5,022.40	$5,022.40	$5,022.40	$5,022.40	$5,022.40	$5,022.40	$5,022.40
CAPACITY COST	$000	Market Capacity	$0.00	$0.00	$0.00	$0.00	$185.33	$402.10	$61.14	$31.85	$0.45	$245.19	$218.94	$576.15	$912.87	$1,225.66	$1,607.67	$2,065.05	$2,448.70	$2,910.38
CAPACITY COST	$000	Nearman Creek	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
CAPACITY COST	$000	NextEra Crystal Lake 3 Wind Farm	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
CAPACITY COST	$000	PPA A	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
CAPACITY COST	$000	Prairie State Energy Campus	$18,600.00	$19,625.00	$18,165.00	$17,200.00	$17,200.00	$17,524.36	$18,137.72	$18,772.54	$19,429.58	$20,109.61	$20,813.45	$21,541.92	$22,295.89	$23,076.24	$23,883.91	$24,719.85	$25,585.03	$26,480.51
CAPACITY COST	$000	Sikeston	$13,527.36	$14,464.55	$14,813.04	$14,612.40	$13,854.72	$14,116.00	$14,610.06	$15,121.41	$15,650.66	$16,198.43	$16,765.38	$17,352.17	$17,959.49	$18,588.07	$19,238.66	$19,912.01	$20,608.93	$21,330.24
FIXED O AND M COST	$000	Wartsila Block x6	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
FIXED O AND M COST	$000	Wartsila Block x6 :2019:700	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$364.71	$377.48	$390.69	$404.36	$418.51	$433.16	$448.32	$464.01	$480.25	$497.06	$514.46	$532.47
FIXED O AND M COST	$000	Wartsila Engine	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
FIXED O AND M COST	$000	Wartsila Engine :2019:699	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$148.16	$153.35	$158.72	$164.27	$170.02	$175.97	$182.13	$188.51	$195.10	$201.93	$209.00	$216.31
FIXED O AND M COST	$000	Wartsila Engine :2020:698	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$153.35	$158.72	$164.27	$170.02	$175.97	$182.13	$188.51	$195.10	$201.93	$209.00	$216.31
FIXED O AND M COST	$000	Wartsila Engine :2021:697	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$158.72	$164.27	$170.02	$175.97	$182.13	$188.51	$195.10	$201.93	$209.00	$216.31
FIXED O AND M COST	$000	Wartsila Engine :2023:696	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$170.02	$175.97	$182.13	$188.51	$195.10	$201.93	$209.00	$216.31
ANNUAL DEBT SERVICE	$000	Wartsila Block x6 :2019:700							$3,310	$3,310	$3,310	$3,310	$3,310	$3,310	$3,310	$3,310	$3,310	$3,310	$3,310	$3,310
ANNUAL DEBT SERVICE	$000	Wartsila Engine :2019:699							$870	$870	$870	$870	$870	$870	$870	$870	$870	$870	$870	$870
ANNUAL DEBT SERVICE	$000	Wartsila Engine :2020:698								$900	$900	$900	$900	$900	$900	$900	$900	$900	$900	$900

Table B-3 CWL CF Base
Columbia Water and Light
Burns & McDonnell Project No. 67546
2012 IRP

Resource Planning Model Output
Case: CWL 4

Data Item	Units	Description	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
ANNUAL DEBT SERVICE	$000	Wartsila Engine :2021:697									$932	$932	$932	$932	$932	$932	$932	$932	$932	$932
ANNUAL DEBT SERVICE	$000	Wartsila Engine :2023:696											$998	$998	$998	$998	$998	$998	$998	$998
VARIABLE O AND M COSTS	$/MWH	7FA Combined Cycle Fully Fired (25% ownership)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
ENERGY COSTS	$/MWH	Ameresco/Columbia LFG	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00
ENERGY COSTS	$/MWH	Blue Grass Ridge	$65.00	$65.00	$65.00	$65.00	$65.00	$65.00	$65.00	$65.00	$65.00	$65.00	$65.00	$65.00	$65.00	$65.00	$65.00	$65.00	$65.00	$65.00
VARIABLE O AND M COSTS	$/MWH	Columbia Energy Center	$1.97	$2.02	$2.07	$2.13	$2.18	$2.23	$2.29	$2.35	$2.40	$2.47	$2.53	$2.58	$2.65	$2.72	$2.79	$2.89	$2.99	$3.09
VARIABLE O AND M COSTS	$/MWH	CWL Unit 5	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$/MWH	CWL Unit 6	$51.62	$53.42	$55.29	$57.23	$59.23	$61.30	$63.45	$65.67	$67.97	$70.35	$72.81	$75.36	$77.99	$80.72	$83.55	$86.47	$89.50	$92.63
VARIABLE O AND M COSTS	$/MWH	CWL Unit 7	$31.35	$32.44	$33.58	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$/MWH	CWL Unit 8	$1.11	$1.15	$1.19	$1.23	$1.27	$1.32	$1.37	$1.41	$1.46	$1.51	$1.57	$1.62	$1.68	$1.74	$1.80	$1.86	$1.93	$1.99
VARIABLE O AND M COSTS	$/MWH	Distributed Generation	$228.06	$236.04	$244.30	$252.85	$261.70	$270.86	$280.34	$290.15	$300.31	$310.82	$321.70	$332.96	$344.61	$356.67	$369.15	$382.08	$395.45	$409.29
ENERGY COSTS	$/MWH	Iatan 2	$17.12	$17.75	$18.46	$19.15	$19.97	$20.77	$21.60	$22.46	$23.36	$24.29	$25.27	$26.28	$27.33	$28.42	$29.56	$30.74	$31.97	$33.25
ENERGY COSTS	$/MWH	Market Capacity	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
ENERGY COSTS	$/MWH	Nearman Creek	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
ENERGY COSTS	$/MWH	NextEra Crystal Lake 3 Wind Farm	$43.50	$44.50	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00
ENERGY COSTS	$/MWH	PPA A	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
ENERGY COSTS	$/MWH	Prairie State Energy Campus	$13.20	$14.30	$14.10	$14.60	$14.70	$15.10	$15.60	$16.00	$16.50	$17.00	$17.50	$18.10	$18.60	$19.20	$19.70	$20.30	$20.90	$21.60
ENERGY COSTS	$/MWH	Sikeston	$24.28	$30.14	$30.97	$31.59	$32.66	$33.80	$34.99	$36.21	$37.48	$38.79	$40.15	$41.55	$43.01	$44.51	$46.07	$47.68	$49.35	$51.08
VARIABLE O AND M COSTS	$/MWH	Wartsila Block x6	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$/MWH	Wartsila Block x6 :2019:700	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$7.76	$8.03	$8.31	$8.60	$8.91	$9.22	$9.54	$9.87	$10.22	$10.58	$10.95	$11.33
VARIABLE O AND M COSTS	$/MWH	Wartsila Engine	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$/MWH	Wartsila Engine :2019:699	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$7.76	$8.03	$8.31	$8.60	$8.91	$9.22	$9.54	$9.87	$10.22	$10.58	$10.95	$11.33
VARIABLE O AND M COSTS	$/MWH	Wartsila Engine :2020:698	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$8.03	$8.31	$8.60	$8.91	$9.22	$9.54	$9.87	$10.22	$10.58	$10.95	$11.33
VARIABLE O AND M COSTS	$/MWH	Wartsila Engine :2021:697	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$8.31	$8.60	$8.91	$9.22	$9.54	$9.87	$10.22	$10.58	$10.95	$11.33
VARIABLE O AND M COSTS	$/MWH	Wartsila Engine :2023:696	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$8.91	$9.22	$9.54	$9.87	$10.22	$10.58	$10.95	$11.33
VARIABLE O AND M COSTS	$000	7FA Combined Cycle Fully Fired (25% ownership)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
ENERGY COSTS	$000	Ameresco/Columbia LFG	$3,405.89	$3,405.89	$3,405.89	$3,415.22	$3,405.89	$3,405.89	$3,405.89	$3,415.22	$3,405.89	$3,405.89	$3,405.89	$3,415.22	$3,405.89	$3,405.89	$3,405.89	$3,415.22	$3,405.89	$3,405.89
ENERGY COSTS	$000	Blue Grass Ridge	$1,004.42	$1,004.42	$1,004.42	$1,007.17	$1,004.42	$1,004.42	$1,004.42	$1,007.17	$1,004.42	$1,004.42	$1,004.42	$1,007.17	$1,004.42	$1,004.42	$1,004.42	$1,007.17	$1,004.42	$1,004.42
VARIABLE O AND M COSTS	$000	Columbia Energy Center	$262.66	$273.06	$290.29	$283.91	$293.74	$308.78	$219.49	$183.76	$153.71	$163.51	$144.88	$150.85	$152.13	$158.67	$178.15	$188.81	$188.91	$188.38
VARIABLE O AND M COSTS	$000	CWL Unit 5	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$000	CWL Unit 6	$16.73	$16.29	$17.23	$26.27	$26.70	$27.73	$17.00	$13.56	$11.57	$13.31	$13.56	$14.70	$15.09	$16.69	$20.84	$22.44	$21.38	$20.83
VARIABLE O AND M COSTS	$000	CWL Unit 7	$25.58	$25.48	$27.48	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$000	CWL Unit 8	$3.37	$3.45	$3.76	$3.28	$3.40	$3.60	$2.27	$1.79	$1.47	$1.65	$1.58	$1.71	$1.72	$1.88	$2.28	$2.45	$2.35	$2.27
VARIABLE O AND M COSTS	$000	Distributed Generation	$56.39	$54.02	$55.88	$74.77	$74.82	$76.06	$45.48	$37.08	$33.17	$38.41	$40.67	$43.83	$45.97	$51.32	$64.90	$70.20	$67.08	$66.09
ENERGY COSTS	$000	Iatan 2	$2,999.42	$3,109.80	$3,234.19	$3,364.27	$3,498.74	$3,638.90	$3,784.32	$3,945.77	$4,092.67	$4,255.61	$4,427.30	$4,616.87	$4,788.22	$4,979.18	$5,178.91	$5,400.40	$5,601.14	$5,825.40
ENERGY COSTS	$000	Market Capacity	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
ENERGY COSTS	$000	Nearman Creek	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
ENERGY COSTS	$000	NextEra Crystal Lake 3 Wind Farm	$1,800.51	$1,841.90	$1,862.59	$1,867.70	$1,862.59	$1,862.59	$1,862.59	$1,867.70	$1,862.59	$1,862.59	$1,862.59	$1,867.70	$1,862.59	$1,862.59	$1,862.59	$1,867.70	$1,862.59	$1,862.59
ENERGY COSTS	$000	PPA A	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
ENERGY COSTS	$000	Prairie State Energy Campus	$5,203.44	$5,637.06	$5,558.22	$5,771.09	$5,794.74	$5,952.42	$6,149.52	$6,324.48	$6,504.30	$6,701.40	$6,898.50	$7,154.57	$7,332.12	$7,568.64	$7,765.74	$8,024.18	$8,238.78	$8,514.72
ENERGY COSTS	$000	Sikeston	$11,089.80	$13,766.34	$14,145.44	$14,468.15	$14,917.34	$15,439.44	$15,979.82	$16,584.43	$17,117.99	$17,717.11	$18,337.21	$19,031.02	$19,643.28	$20,330.80	$21,042.37	$21,838.53	$22,541.12	$23,330.06
VARIABLE O AND M COSTS	$000	Wartsila Block x6	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$000	Wartsila Block x6 :2019:700	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$221.51	$190.26	$162.51	$171.54	$151.14	$157.61	$160.71	$167.50	$187.25	$197.28	$199.91	$201.40
VARIABLE O AND M COSTS	$000	Wartsila Engine	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$000	Wartsila Engine :2019:699	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$271.43	$235.99	$202.85	$213.65	$187.64	$195.54	$199.46	$207.58	$231.69	$243.90	$247.75	$250.07
VARIABLE O AND M COSTS	$000	Wartsila Engine :2020:698	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$288.31	$250.83	$263.68	$231.87	$241.62	$246.66	$256.38	$285.13	$299.91	$305.45	$309.09
VARIABLE O AND M COSTS	$000	Wartsila Engine :2021:697	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$305.34	$320.41	$283.85	$295.87	$302.43	$314.01	$347.07	$364.70	$372.43	$378.07
VARIABLE O AND M COSTS	$000	Wartsila Engine :2023:696	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$342.14	$356.76	$365.22	$378.87	$415.27	$435.82	$446.19	$454.52
TOTAL FUEL COST	$000	7FA Combined Cycle Fully Fired (25% ownership)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL FUEL COST	$000	Ameresco/Columbia LFG	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL FUEL COST	$000	Blue Grass Ridge	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL FUEL COST	$000	Columbia Energy Center	$8,181.00	$8,656.58	$9,189.70	$9,185.83	$9,770.26	$10,491.90	$7,509.54	$6,489.79	$5,695.10	$6,234.62	$5,631.74	$5,944.18	$6,193.52	$6,615.40	$7,399.02	$7,661.40	$7,625.82	$7,748.86
TOTAL FUEL COST	$000	CWL Unit 5	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL FUEL COST	$000	CWL Unit 6	$27.63	$27.10	$28.30	$43.87	$45.39	$47.63	$28.79	$23.38	$20.69	$24.25	$24.96	$27.12	$28.51	$32.00	$39.50	$41.59	$39.50	$39.13
TOTAL FUEL COST	$000	CWL Unit 7	$62.33	$61.19	$64.53	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL FUEL COST	$000	CWL Unit 8	$200.97	$207.73	$223.78	$198.45	$209.02	$223.92	$139.65	$112.45	$95.48	$109.83	$105.94	$114.60	$118.45	$130.88	$157.37	$164.94	$157.70	$155.29
TOTAL FUEL COST	$000	Distributed Generation	$55.92	$53.57	$55.42	$74.09	$74.15	$75.37	$45.05	$36.73	$32.86	$38.04	$40.28	$43.42	$45.54	$50.83	$64.23	$69.49	$66.42	$65.39
TOTAL FUEL COST	$000	Iatan 2	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL FUEL COST	$000	Market Capacity	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL FUEL COST	$000	Nearman Creek	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL FUEL COST	$000	NextEra Crystal Lake 3 Wind Farm	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL FUEL COST	$000	PPA A	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL FUEL COST	$000	Prairie State Energy Campus	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL FUEL COST	$000	Sikeston	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL FUEL COST	$000	Wartsila Block x6	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL FUEL COST	$000	Wartsila Block x6 :2019:700	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$1,547.39	$1,359.42	$1,207.01	$1,298.62	$1,155.91	$1,210.29	$1,262.23	$1,334.54	$1,471.16	$1,514.09	$1,525.77	$1,566.38
TOTAL FUEL COST	$000	Wartsila Engine	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL FUEL COST	$000	Wartsila Engine :2019:699	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$1,897.44	$1,687.58	$1,507.77	$1,618.65	$1,436.18	$1,502.73	$1,567.63	$1,655.07	$1,821.60	$1,873.23	$1,892.16	$1,946.13
TOTAL FUEL COST	$000	Wartsila Engine :2020:698	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$2,063.35	$1,865.86	$1,999.25	$1,776.19	$1,858.48	$1,940.09	$2,045.83	$2,243.33	$2,304.86	$2,334.26	$2,406.91
TOTAL FUEL COST	$000	Wartsila Engine :2021:697	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$2,273.02	$2,431.12	$2,176.18	$2,277.85	$2,380.53	$2,507.70	$2,732.53	$2,804.72	$2,847.91	$2,945.58
TOTAL FUEL COST	$000	Wartsila Engine :2023:696	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$2,625.11	$2,748.96	$2,876.94	$3,027.98	$3,271.42	$3,353.57	$3,413.89	$3,543.22
TOTAL VARIABLE COST	$/MWH	7FA Combined Cycle Fully Fired (25% ownership)																		
TOTAL ENERGY COSTS	$/MWH	Ameresco/Columbia LFG	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00
TOTAL ENERGY COSTS	$/MWH	Blue Grass Ridge	$65.00	$65.00	$65.00	$65.00	$65.00	$65.00	$65.00	$65.00	$65.00	$65.00	$65.00	$65.00	$65.00	$65.00	$65.00	$65.00	$65.00	$65.00
TOTAL VARIABLE COST	$/MWH	Columbia Energy Center	$63.45	$66.16	$67.72	$70.90	$74.65	$78.11	$80.60	$85.21	$91.51	$96.46	$100.74	$104.64	$110.72	$116.17	$118.62	$120.02	$123.59	$130.28
TOTAL VARIABLE COST	$/MWH	CWL Unit 5																		
TOTAL VARIABLE COST	$/MWH	CWL Unit 6	$136.85	$142.25	$146.12	$152.77	$159.93	$166.61	$170.89	$178.90	$189.50	$198.55	$206.87	$214.42	$225.36	$235.46	$241.88	$246.74	$254.83	$266.64
TOTAL VARIABLE COST	$/MWH	CWL Unit 7	$107.72	$110.37	$112.43															

Table B-3 CWL CF Base
Columbia Water and Light
Burns & McDonnell Project No. 67546
2012 IRP

Resource Planning Model Output
Case: CWL 4

Data Item	Units	Description	2013	2014	2015	2016	2017	2018	2019	2020	2021
TOTAL VARIABLE COST	$/MWH	CWL Unit 8	$67.44	$70.33	$71.96	$75.65	$79.70	$83.40	$85.49	$90.17	$96.75
TOTAL VARIABLE COST	$/MWH	Distributed Generation	$454.18	$470.10	$486.59	$503.39	$521.05	$539.27	$558.03	$577.51	$597.75
TOTAL ENERGY COSTS	$/MWH	Iatan 2	$17.12	$17.75	$18.46	$19.15	$19.97	$20.77	$21.60	$22.46	$23.36
TOTAL ENERGY COSTS	$/MWH	Market Capacity									
TOTAL ENERGY COSTS	$/MWH	Nearman Creek									
TOTAL ENERGY COSTS	$/MWH	NextEra Crystal Lake 3 Wind Farm	$43.50	$44.50	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00
TOTAL ENERGY COSTS	$/MWH	PPA A									
TOTAL ENERGY COSTS	$/MWH	Prairie State Energy Campus	$13.20	$14.30	$14.10	$14.60	$14.70	$15.10	$15.60	$16.00	$16.50
TOTAL ENERGY COSTS	$/MWH	Sikeston	$24.28	$30.14	$30.97	$31.59	$32.66	$33.80	$34.99	$36.21	$37.48
TOTAL VARIABLE COST	$/MWH	Wartsila Block x6									
TOTAL VARIABLE COST	$/MWH	Wartsila Block x6 :2019:700							$61.98	$65.43	$70.06
TOTAL VARIABLE COST	$/MWH	Wartsila Engine									
TOTAL VARIABLE COST	$/MWH	Wartsila Engine :2019:699							$62.01	$65.47	$70.11
TOTAL VARIABLE COST	$/MWH	Wartsila Engine :2020:698								$65.52	$70.16
TOTAL VARIABLE COST	$/MWH	Wartsila Engine :2021:697									$70.20
TOTAL VARIABLE COST	$/MWH	Wartsila Engine :2023:696									
SYSTEM EFFLUENT EXPENSE	$000	NOx	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
SYSTEM EFFLUENT EXPENSE	$000	CO2	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
SYSTEM EFFLUENT EXPENSE	$000	SO2	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
SYSTEM EFFLUENT EXPENSE	$000	Hg	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
SYSTEM EFFLUENT EXPENSE	$000	CO	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
SUMMARY OF COSTS											
TOTAL FIXED COSTS	$000		$15,863	$16,299	$16,747	$15,579	$15,996	$16,772	$17,734	$18,367	$19,023
TOTAL VARIABLE (EXCL. FUEL) COSTS	$000		$4,923	$5,864	$6,661	$8,193	$9,752	$11,389	$12,106	$13,542	$15,494
TOTAL FUEL COSTS	$000		$8,528	$9,006	$9,562	$9,502	$10,099	$10,839	$11,168	$11,773	$12,698
TOTAL DEBT SERVICE COSTS	$000		$0	$0	$0	$0	$0	$0	$4,180	$5,080	$6,012
TOTAL PURCHASE COSTS	$000		$62,681	$67,980	$67,203	$66,728	$66,746	$68,369	$70,018	$72,093	$74,091
TOTAL COSTS	$000		$91,994	$99,149	$100,173	$100,002	$102,593	$107,369	$115,206	$120,854	$127,318

Data Item	Units	Description	2022	2023	2024	2025	2026	2027	2028	2029	2030
TOTAL VARIABLE COST	$/MWH	CWL Unit 8	$102.03	$106.57	$110.59	$117.16	$122.99	$125.77	$127.29	$131.20	$138.18
TOTAL VARIABLE COST	$/MWH	Distributed Generation	$618.66	$640.36	$662.76	$685.95	$709.96	$734.55	$760.29	$786.99	$814.23
TOTAL ENERGY COSTS	$/MWH	Iatan 2	$24.29	$25.27	$26.28	$27.33	$28.42	$29.56	$30.74	$31.97	$33.25
TOTAL ENERGY COSTS	$/MWH	Market Capacity									
TOTAL ENERGY COSTS	$/MWH	Nearman Creek									
TOTAL ENERGY COSTS	$/MWH	NextEra Crystal Lake 3 Wind Farm	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00
TOTAL ENERGY COSTS	$/MWH	PPA A									
TOTAL ENERGY COSTS	$/MWH	Prairie State Energy Campus	$17.00	$17.50	$18.10	$18.60	$19.20	$19.70	$20.30	$20.90	$21.60
TOTAL ENERGY COSTS	$/MWH	Sikeston	$38.79	$40.15	$41.55	$43.01	$44.51	$46.07	$47.68	$49.35	$51.08
TOTAL VARIABLE COST	$/MWH	Wartsila Block x6									
TOTAL VARIABLE COST	$/MWH	Wartsila Block x6 :2019:700	$73.74	$77.01	$80.00	$84.47	$88.54	$90.51	$91.76	$94.50	$99.46
TOTAL VARIABLE COST	$/MWH	Wartsila Engine									
TOTAL VARIABLE COST	$/MWH	Wartsila Engine :2019:699	$73.79	$77.07	$80.06	$84.52	$88.60	$90.57	$91.81	$94.56	$99.51
TOTAL VARIABLE COST	$/MWH	Wartsila Engine :2020:698	$73.85	$77.13	$80.12	$84.58	$88.66	$90.63	$91.87	$94.61	$99.56
TOTAL VARIABLE COST	$/MWH	Wartsila Engine :2021:697	$73.89	$77.18	$80.18	$84.63	$88.73	$90.68	$91.92	$94.66	$99.61
TOTAL VARIABLE COST	$/MWH	Wartsila Engine :2023:696		$77.24	$80.24	$84.69	$88.79	$90.73	$91.97	$94.71	$99.66
SYSTEM EFFLUENT EXPENSE	$000	NOx	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
SYSTEM EFFLUENT EXPENSE	$000	CO2	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
SYSTEM EFFLUENT EXPENSE	$000	SO2	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
SYSTEM EFFLUENT EXPENSE	$000	Hg	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
SYSTEM EFFLUENT EXPENSE	$000	CO	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
SUMMARY OF COSTS											
TOTAL FIXED COSTS	$000		$19,541	$20,242	$20,794	$21,362	$21,946	$22,545	$23,056	$23,863	$24,698
TOTAL VARIABLE (EXCL. FUEL) COSTS	$000		$18,070	$19,911	$22,600	$26,169	$28,543	$30,335	$32,774	$36,192	$40,253
TOTAL FUEL COSTS	$000		$13,754	$14,972	$15,728	$16,413	$17,400	$19,200	$19,768	$19,903	$20,417
TOTAL DEBT SERVICE COSTS	$000		$6,012	$7,010	$7,010	$7,010	$7,010	$7,010	$7,010	$7,010	$7,010
TOTAL PURCHASE COSTS	$000		$76,523	$78,756	$81,585	$84,227	$87,064	$90,013	$93,273	$96,319	$99,687
TOTAL COSTS	$000		$133,899	$140,892	$147,717	$155,182	$161,963	$169,103	$175,900	$183,287	$192,065

NPV @ 4.0% ($000): $1,626,830

Table B-4 CWL CF Gas Sensitivity
Columbia Water and Light
Burns & McDonnell Project No. 67546
2012 IRP

Resource Planning Model Output
Case: CWL 4

Data Item	Units	Description	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
ENERGY REQUIREMENTS	GWH		1251.00	1278.00	1304.00	1329.00	1358.00	1393.00	1427.00	1461.00	1495.00	1532.00	1569.00	1607.00	1645.00	1663.00	1695.00	1727.00	1760.00	1792.00
PEAK DEMAND	MW		285.00	289.00	294.00	300.00	306.00	312.00	318.00	325.00	332.00	338.00	345.00	353.00	360.00	366.00	373.00	381.00	387.00	394.00
REQUIRED RESERVES	MW		46.40	47.05	47.86	48.84	49.82	50.79	51.77	52.91	54.05	55.03	56.17	57.47	58.61	59.58	60.72	62.03	63.00	64.14
TOTAL CAPACITY RESPONSIBILITY	MW		331.40	336.05	341.86	348.84	355.82	362.79	369.77	377.91	386.05	393.03	401.17	410.47	418.61	425.58	433.72	443.03	450.00	458.14
TOTAL FIRM RESOURCES	MW		388.17	388.17	388.17	349.67	355.85	367.87	376.97	377.94	386.08	393.06	401.20	410.50	418.64	425.62	433.76	443.06	450.04	458.18
RESERVE SURPLUS/(DEFICIT)	MW		56.77	52.12	46.31	0.83	0.03	5.08	7.20	0.03	0.03	0.03	0.03	0.04	0.04	0.04	0.04	0.04	0.04	0.04
RESERVE MARGIN	%		36%	34%	32%	17%	16%	18%	19%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%	16%
DUMP ENERGY	GWH		153.95	151.08	146.18	149.85	147.78	129.10	121.89	123.31	120.07	119.78	120.80	117.85	121.07	122.18	119.95	117.73	116.87	122.67
ECONOMY INTERCHANGE PURCHASE ENERGY	GWH		162.91	186.89	205.41	233.84	263.63	269.72	290.92	324.68	355.97	391.62	429.21	456.56	503.02	521.93	542.12	566.61	606.11	645.14
ECONOMY INTERCHANGE SALES ENERGY	GWH		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ECONOMY INTERCHANGE PURCHASE COST	$000		$7,563.19	$8,794.46	$9,907.79	$11,349.32	$13,222.53	$14,144.11	$15,754.11	$18,075.13	$20,440.58	$23,677.21	$26,871.16	$29,485.75	$33,432.48	$36,372.04	$38,801.53	$41,555.42	$45,015.66	$49,329.18
ECONOMY INTERCHANGE SALES COST	$000		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
EMERGENCY ENERGY	GWH		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
EMERGENCY COST	$000		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TRANSACTION PURCHASE COST	$000		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TRANSACTION SALES COST	$000		$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
FIRM CAPACITY	MW	7FA Combined Cycle Fully Fired (25% ownership)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FIRM CAPACITY	MW	Ameresco/Columbia LFG	7.20	7.20	7.20	7.20	7.20	7.20	7.20	7.20	7.20	7.20	7.20	7.20	7.20	7.20	7.20	7.20	7.20	7.20
FIRM CAPACITY	MW	Blue Grass Ridge	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93	0.93
FIRM CAPACITY	MW	Columbia Energy Center	144.00	144.00	144.00	144.00	144.00	144.00	144.00	144.00	144.00	144.00	144.00	144.00	144.00	144.00	144.00	144.00	144.00	144.00
FIRM CAPACITY	MW	CWL Unit 5	16.50	16.50	16.50	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FIRM CAPACITY	MW	CWL Unit 6	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50
FIRM CAPACITY	MW	CWL Unit 7	22.00	22.00	22.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FIRM CAPACITY	MW	CWL Unit 8	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00
FIRM CAPACITY	MW	Distributed Generation	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50
FIRM CAPACITY	MW	Iatan 2	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00
FIRM CAPACITY	MW	Market Capacity	0.00	0.00	0.00	0.00	6.18	0.00	0.00	0.97	0.01	6.99	15.13	15.33	23.47	30.45	38.59	47.90	54.87	63.01
FIRM CAPACITY	MW	Nearman Creek	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FIRM CAPACITY	MW	NextEra Crystal Lake 3 Wind Farm	1.54	1.54	1.54	1.54	1.54	1.54	1.54	1.54	1.54	1.54	1.54	1.54	1.54	1.54	1.54	1.54	1.54	1.54
FIRM CAPACITY	MW	PPA A	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FIRM CAPACITY	MW	Prairie State Energy Campus	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00
FIRM CAPACITY	MW	Sikeston	66.00	66.00	66.00	66.00	66.00	66.00	66.00	66.00	66.00	66.00	66.00	66.00	66.00	66.00	66.00	66.00	66.00	66.00
FIRM CAPACITY	MW	Wartsila Block x6	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FIRM CAPACITY	MW	Wartsila Block x6 :2018:700	0.00	0.00	0.00	0.00	0.00	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10
FIRM CAPACITY	MW	Wartsila Engine	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FIRM CAPACITY	MW	Wartsila Engine :2018:699	0.00	0.00	0.00	0.00	0.00	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10
FIRM CAPACITY	MW	Wartsila Engine :2019:698	0.00	0.00	0.00	0.00	0.00	0.00	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10
FIRM CAPACITY	MW	Wartsila Engine :2021:697	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10
FIRM CAPACITY	MW	Wartsila Engine :2024:696	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	9.10	9.10	9.10	9.10	9.10	9.10	9.10
MAXIMUM CAPACITY	MW	7FA Combined Cycle Fully Fired (25% ownership)	381.50	381.50	381.50	381.50	381.50	381.50	381.50	381.50	381.50	381.50	381.50	381.50	381.50	381.50	381.50	381.50	381.50	381.50
MAXIMUM CAPACITY	MW	Ameresco/Columbia LFG	7.20	7.20	7.20	7.20	7.20	7.20	7.20	7.20	7.20	7.20	7.20	7.20	7.20	7.20	7.20	7.20	7.20	7.20
MAXIMUM CAPACITY	MW	Blue Grass Ridge	6.30	6.30	6.30	6.30	6.30	6.30	6.30	6.30	6.30	6.30	6.30	6.30	6.30	6.30	6.30	6.30	6.30	6.30
MAXIMUM CAPACITY	MW	Columbia Energy Center	144.00	144.00	144.00	144.00	144.00	144.00	144.00	144.00	144.00	144.00	144.00	144.00	144.00	144.00	144.00	144.00	144.00	144.00
MAXIMUM CAPACITY	MW	CWL Unit 5	16.50	16.50	16.50	16.50	16.50	16.50	16.50	16.50	16.50	16.50	16.50	16.50	16.50	16.50	16.50	16.50	16.50	16.50
MAXIMUM CAPACITY	MW	CWL Unit 6	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50
MAXIMUM CAPACITY	MW	CWL Unit 7	22.00	22.00	22.00	22.00	22.00	22.00	22.00	22.00	22.00	22.00	22.00	22.00	22.00	22.00	22.00	22.00	22.00	22.00
MAXIMUM CAPACITY	MW	CWL Unit 8	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00	35.00
MAXIMUM CAPACITY	MW	Distributed Generation	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50	12.50
MAXIMUM CAPACITY	MW	Iatan 2	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00
MAXIMUM CAPACITY	MW	Market Capacity	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
MAXIMUM CAPACITY	MW	Nearman Creek	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00
MAXIMUM CAPACITY	MW	NextEra Crystal Lake 3 Wind Farm	10.50	10.50	10.50	10.50	10.50	10.50	10.50	10.50	10.50	10.50	10.50	10.50	10.50	10.50	10.50	10.50	10.50	10.50
MAXIMUM CAPACITY	MW	PPA A	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00	20.00
MAXIMUM CAPACITY	MW	Prairie State Energy Campus	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00	50.00
MAXIMUM CAPACITY	MW	Sikeston	66.00	66.00	66.00	66.00	66.00	66.00	66.00	66.00	66.00	66.00	66.00	66.00	66.00	66.00	66.00	66.00	66.00	66.00
MAXIMUM CAPACITY	MW	Wartsila Block x6	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10
MAXIMUM CAPACITY	MW	Wartsila Block x6 :2018:700	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10
MAXIMUM CAPACITY	MW	Wartsila Engine	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10
MAXIMUM CAPACITY	MW	Wartsila Engine :2018:699	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10
MAXIMUM CAPACITY	MW	Wartsila Engine :2019:698	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10
MAXIMUM CAPACITY	MW	Wartsila Engine :2021:697	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10
MAXIMUM CAPACITY	MW	Wartsila Engine :2024:696	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10	9.10
GENERATION	GWH	7FA Combined Cycle Fully Fired (25% ownership)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
GENERATION	GWH	Ameresco/Columbia LFG	56.76	56.76	56.76	56.92	56.76	56.76	56.76	56.92	56.76	56.76	56.76	56.92	56.76	56.76	56.76	56.92	56.76	56.76
GENERATION	GWH	Blue Grass Ridge	15.45	15.45	15.45	15.49	15.45	15.45	15.45	15.49	15.45	15.45	15.45	15.49	15.45	15.45	15.45	15.49	15.45	15.45
GENERATION	GWH	Columbia Energy Center	95.91	96.02	98.45	99.37	99.58	63.04	49.82	49.06	37.18	37.71	38.08	29.47	28.93	29.12	32.74	33.44	32.75	31.68
GENERATION	GWH	CWL Unit 5	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
GENERATION	GWH	CWL Unit 6	0.29	0.29	0.30	0.44	0.45	0.19	0.13	0.13	0.09	0.09	0.10	0.07	0.08	0.08	0.16	0.16	0.17	0.17
GENERATION	GWH	CWL Unit 7	4.14	4.23	4.31	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
GENERATION	GWH	CWL Unit 8	1.68	1.63	1.69	1.96	1.99	0.88	0.59	0.60	0.38	0.39	0.42	0.29	0.30	0.31	0.56	0.56	0.57	0.57
GENERATION	GWH	Distributed Generation	0.27	0.27	0.27	0.36	0.38	0.16	0.10	0.12	0.08	0.08	0.09	0.06	0.07	0.07	0.15	0.15	0.16	0.16
GENERATION	GWH	Iatan 2	175.20	175.20	175.20	175.68	175.20	175.20	175.20	175.68	175.20	175.20	175.20	175.68	175.20	175.20	175.20	175.68	175.20	175.20
GENERATION	GWH	Market Capacity	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
GENERATION	GWH	Nearman Creek	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
GENERATION	GWH	NextEra Crystal Lake 3 Wind Farm	41.39	41.39	41.39	41.50	41.39	41.39	41.39	41.50	41.39	41.39	41.39	41.50	41.39	41.39	41.39	41.50	41.39	41.39
GENERATION	GWH	PPA A	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
GENERATION	GWH	Prairie State Energy Campus	394.20	394.20	394.20	395.28	394.20	394.20	394.20	395.28	394.20	394.20	394.20	395.28	394.20	394.20	394.20	395.28	394.20	394.20
GENERATION	GWH	Sikeston	456.75	456.75	456.75	458.00	456.75	456.75	456.75	458.00	456.75	456.75	456.75	458.00	456.75	456.75	456.75	458.00	456.75	456.75
GENERATION	GWH	Wartsila Block x6	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
GENERATION	GWH	Wartsila Block x6 :2018:700	0.00	0.00	0.00	0.00	0.00	21.28	17.32	17.11	13.59	13.70	13.73	11.08	10.90	10.92	11.69	11.88	11.66	11.38
GENERATION	GWH	Wartsila Engine	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Table B-4 CWL CF Gas Sensitivity
Columbia Water and Light
Burns & McDonnell Project No. 67546
2012 IRP

Resource Planning Model Output
Case: CWL 4

Data Item	Units	Description	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
GENERATION	GWH	Wartsila Engine :2018:699	0.00	0.00	0.00	0.00	0.00	27.07	22.16	21.91	17.44	17.57	17.58	14.18	13.95	13.97	14.92	15.15	14.88	14.53
GENERATION	GWH	Wartsila Engine :2019:698	0.00	0.00	0.00	0.00	0.00	0.00	28.09	27.83	22.31	22.45	22.44	18.11	17.81	17.82	18.96	19.24	18.93	18.50
GENERATION	GWH	Wartsila Engine :2021:697	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	28.29	28.43	28.40	23.06	22.67	22.66	23.96	24.31	23.94	23.43
GENERATION	GWH	Wartsila Engine :2024:696	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	29.08	28.59	28.55	29.93	30.35	29.94	29.35
CAPACITY FACTOR	%	7FA Combined Cycle Fully Fired (25% ownership)																		
CAPACITY FACTOR	%	Ameresco/Columbia LFG	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%
CAPACITY FACTOR	%	Blue Grass Ridge	28.00%	28.00%	28.00%	28.00%	28.00%	28.00%	28.00%	28.00%	28.00%	28.00%	28.00%	28.00%	28.00%	28.00%	28.00%	28.00%	28.00%	28.00%
CAPACITY FACTOR	%	Columbia Energy Center	7.60%	7.61%	7.80%	7.86%	7.89%	5.00%	3.95%	3.88%	2.95%	2.99%	3.02%	2.33%	2.29%	2.31%	2.60%	2.64%	2.60%	2.51%
CAPACITY FACTOR	%	CWL Unit 5	0.00%	0.00%	0.00%															
CAPACITY FACTOR	%	CWL Unit 6	0.27%	0.27%	0.27%	0.40%	0.41%	0.17%	0.11%	0.12%	0.08%	0.08%	0.09%	0.06%	0.07%	0.07%	0.15%	0.15%	0.15%	0.16%
CAPACITY FACTOR	%	CWL Unit 7	2.15%	2.19%	2.24%															
CAPACITY FACTOR	%	CWL Unit 8	0.55%	0.53%	0.55%	0.64%	0.65%	0.29%	0.19%	0.19%	0.12%	0.13%	0.14%	0.10%	0.10%	0.10%	0.18%	0.18%	0.19%	0.19%
CAPACITY FACTOR	%	Distributed Generation	0.24%	0.24%	0.25%	0.33%	0.34%	0.14%	0.10%	0.11%	0.07%	0.07%	0.08%	0.06%	0.06%	0.06%	0.14%	0.14%	0.14%	0.15%
CAPACITY FACTOR	%	Iatan 2	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%
CAPACITY FACTOR	%	Market Capacity					0.00%			0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
CAPACITY FACTOR	%	Nearman Creek																		
CAPACITY FACTOR	%	NextEra Crystal Lake 3 Wind Farm	45.00%	45.00%	45.00%	45.00%	45.00%	45.00%	45.00%	45.00%	45.00%	45.00%	45.00%	45.00%	45.00%	45.00%	45.00%	45.00%	45.00%	45.00%
CAPACITY FACTOR	%	PPA A																		
CAPACITY FACTOR	%	Prairie State Energy Campus	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%	90.00%
CAPACITY FACTOR	%	Sikeston	79.00%	79.00%	79.00%	79.00%	79.00%	79.00%	79.00%	79.00%	79.00%	79.00%	79.00%	79.00%	79.00%	79.00%	79.00%	79.00%	79.00%	79.00%
CAPACITY FACTOR	%	Wartsila Block x6																		
CAPACITY FACTOR	%	Wartsila Block x6 :2018:700						26.70%	21.73%	21.40%	17.05%	17.19%	17.22%	13.86%	13.67%	13.70%	14.67%	14.86%	14.63%	14.27%
CAPACITY FACTOR	%	Wartsila Engine																		
CAPACITY FACTOR	%	Wartsila Engine :2018:699						33.96%	27.80%	27.41%	21.88%	22.04%	22.06%	17.74%	17.50%	17.52%	18.72%	18.95%	18.67%	18.23%
CAPACITY FACTOR	%	Wartsila Engine :2019:698							35.24%	34.82%	27.99%	28.16%	28.16%	22.66%	22.35%	22.36%	23.79%	24.07%	23.75%	23.21%
CAPACITY FACTOR	%	Wartsila Engine :2021:697									35.49%	35.66%	35.62%	28.84%	28.44%	28.42%	30.05%	30.41%	30.03%	29.39%
CAPACITY FACTOR	%	Wartsila Engine :2024:696												36.38%	35.86%	35.81%	37.54%	37.97%	37.56%	36.82%
TOTAL O AND M COST	$000	7FA Combined Cycle Fully Fired (25% ownership)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL PURCHASE COST	$000	Ameresco/Columbia LFG	$3,405.89	$3,405.89	$3,405.89	$3,415.22	$3,405.89	$3,405.89	$3,405.89	$3,415.22	$3,405.89	$3,405.89	$3,405.89	$3,415.22	$3,405.89	$3,405.89	$3,405.89	$3,415.22	$3,405.89	$3,405.89
TOTAL PURCHASE COST	$000	Blue Grass Ridge	$1,004.42	$1,004.42	$1,004.42	$1,007.17	$1,004.42	$1,004.42	$1,004.42	$1,007.17	$1,004.42	$1,004.42	$1,004.42	$1,007.17	$1,004.42	$1,004.42	$1,004.42	$1,007.17	$1,004.42	$1,004.42
TOTAL O AND M COST	$000	Columbia Energy Center	$12,084.81	$12,387.15	$12,701.88	$13,021.38	$13,347.37	$13,947.51	$14,265.92	$14,620.79	$14,957.72	$15,332.98	$15,717.25	$16,087.89	$16,488.64	$16,901.37	$17,334.02	$17,664.40	$18,280.58	$18,917.11
TOTAL O AND M COST	$000	CWL Unit 5	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL O AND M COST	$000	CWL Unit 6	$1,778.82	$1,841.05	$1,905.97	$1,980.73	$2,050.67	$2,106.37	$2,176.03	$2,252.83	$2,328.39	$2,410.03	$2,495.07	$2,580.37	$2,671.05	$2,764.78	$2,868.59	$2,968.95	$3,073.40	$3,181.17
TOTAL O AND M COST	$000	CWL Unit 7	$1,893.30	$1,962.46	$2,033.93	$325.47	$336.86	$348.65	$360.85	$373.48	$386.56	$400.09	$414.09	$428.58	$443.58	$459.11	$475.18	$491.81	$509.02	$526.84
TOTAL O AND M COST	$000	CWL Unit 8	$441.68	$457.08	$473.14	$490.04	$507.22	$523.51	$541.44	$560.40	$579.70	$600.00	$621.05	$642.58	$665.09	$688.39	$712.92	$737.88	$763.72	$790.45
TOTAL O AND M COST	$000	Distributed Generation	$60.96	$63.15	$67.16	$92.25	$98.23	$42.62	$29.29	$33.55	$22.63	$23.88	$27.61	$21.04	$23.38	$25.15	$56.17	$57.80	$62.48	$65.76
TOTAL PURCHASE COST	$000	Iatan 2	$8,049.42	$8,235.00	$8,248.59	$8,386.67	$8,521.14	$8,661.30	$8,806.72	$8,968.17	$9,115.07	$9,278.01	$9,449.70	$9,639.27	$9,810.62	$10,001.58	$10,201.31	$10,422.80	$10,623.54	$10,847.80
TOTAL PURCHASE COST	$000	Market Capacity	$0.00	$0.00	$0.00	$0.00	$185.33	$0.00	$0.00	$31.85	$0.45	$245.19	$549.29	$576.15	$912.87	$1,225.66	$1,607.67	$2,065.05	$2,448.70	$2,910.38
TOTAL PURCHASE COST	$000	Nearman Creek	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL PURCHASE COST	$000	NextEra Crystal Lake 3 Wind Farm	$1,800.51	$1,841.90	$1,862.59	$1,867.70	$1,862.59	$1,862.59	$1,862.59	$1,867.70	$1,862.59	$1,862.59	$1,862.59	$1,867.70	$1,862.59	$1,862.59	$1,862.59	$1,867.70	$1,862.59	$1,862.59
TOTAL PURCHASE COST	$000	PPA A	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL PURCHASE COST	$000	Prairie State Energy Campus	$23,803.44	$25,262.06	$23,723.22	$22,971.09	$22,994.74	$23,476.78	$24,287.24	$25,097.02	$25,933.88	$26,811.01	$27,711.95	$28,696.49	$29,628.01	$30,644.88	$31,649.65	$32,744.04	$33,823.81	$34,995.23
TOTAL PURCHASE COST	$000	Sikeston	$24,617.16	$28,230.89	$28,958.47	$29,080.55	$28,772.06	$29,555.44	$30,589.88	$31,705.84	$32,768.65	$33,915.54	$35,102.59	$36,383.19	$37,602.77	$38,918.86	$40,281.03	$41,750.54	$43,150.05	$44,660.30
TOTAL O AND M COST	$000	Wartsila Block x6	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL O AND M COST	$000	Wartsila Block x6 :2018:700	$0.00	$0.00	$0.00	$0.00	$0.00	$511.96	$499.14	$514.88	$503.68	$522.28	$540.78	$535.30	$552.30	$571.82	$599.75	$622.70	$642.16	$661.37
TOTAL O AND M COST	$000	Wartsila Engine	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL O AND M COST	$000	Wartsila Engine :2018:699	$0.00	$0.00	$0.00	$0.00	$0.00	$346.13	$320.13	$329.32	$303.72	$315.42	$326.60	$306.68	$315.24	$326.44	$347.57	$362.13	$371.95	$380.99
TOTAL O AND M COST	$000	Wartsila Engine :2019:698	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$366.20	$376.92	$344.22	$357.42	$369.90	$342.91	$352.08	$364.49	$388.88	$405.47	$416.23	$425.96
TOTAL O AND M COST	$000	Wartsila Engine :2021:697	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$393.92	$408.87	$422.92	$388.49	$398.38	$412.24	$439.93	$458.02	$471.10	$481.79
TOTAL O AND M COST	$000	Wartsila Engine :2024:696	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$444.03	$454.85	$470.40	$500.93	$522.93	$536.82	$548.92
FIXED O AND M COST	$000	7FA Combined Cycle Fully Fired (25% ownership)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
CAPACITY COST	$000	Ameresco/Columbia LFG	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
CAPACITY COST	$000	Blue Grass Ridge	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
FIXED O AND M COST	$000	Columbia Energy Center	$11,895.51	$12,192.89	$12,497.72	$12,810.16	$13,130.41	$13,806.72	$14,151.88	$14,505.68	$14,868.32	$15,240.03	$15,621.03	$16,011.56	$16,411.85	$16,822.14	$17,242.70	$17,567.87	$18,182.75	$18,819.14
FIXED O AND M COST	$000	CWL Unit 5	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
FIXED O AND M COST	$000	CWL Unit 6	$1,763.74	$1,825.47	$1,889.37	$1,955.49	$2,023.94	$2,094.77	$2,168.09	$2,243.97	$2,322.51	$2,403.80	$2,487.93	$2,575.01	$2,665.14	$2,756.42	$2,854.96	$2,954.89	$3,058.31	$3,165.35
FIXED O AND M COST	$000	CWL Unit 7	$1,763.66	$1,825.38	$1,889.27	$325.47	$336.86	$348.65	$360.85	$373.48	$386.56	$400.09	$414.09	$428.58	$443.58	$459.11	$475.18	$491.81	$509.02	$526.84
FIXED O AND M COST	$000	CWL Unit 8	$439.81	$455.20	$471.13	$487.62	$504.69	$522.35	$540.64	$559.56	$579.14	$599.41	$620.39	$642.11	$664.58	$687.84	$711.92	$736.83	$762.62	$789.31
FIXED O AND M COST	$000	Distributed Generation	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
CAPACITY COST	$000	Iatan 2	$5,050.00	$5,125.20	$5,014.40	$5,022.40	$5,022.40	$5,022.40	$5,022.40	$5,022.40	$5,022.40	$5,022.40	$5,022.40	$5,022.40	$5,022.40	$5,022.40	$5,022.40	$5,022.40	$5,022.40	$5,022.40
CAPACITY COST	$000	Market Capacity	$0.00	$0.00	$0.00	$0.00	$185.33	$0.00	$0.00	$31.85	$0.45	$245.19	$549.29	$576.15	$912.87	$1,225.66	$1,607.67	$2,065.05	$2,448.70	$2,910.38
CAPACITY COST	$000	Nearman Creek	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
CAPACITY COST	$000	NextEra Crystal Lake 3 Wind Farm	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
CAPACITY COST	$000	PPA A	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
CAPACITY COST	$000	Prairie State Energy Campus	$18,600.00	$19,625.00	$18,165.00	$17,200.00	$17,200.00	$17,524.36	$18,137.72	$18,772.54	$19,429.58	$20,109.61	$20,813.45	$21,541.92	$22,295.89	$23,076.24	$23,883.91	$24,719.85	$25,585.03	$26,480.51
CAPACITY COST	$000	Sikeston	$13,527.36	$14,464.55	$14,813.04	$14,612.40	$13,854.72	$14,116.00	$14,610.06	$15,121.41	$15,650.66	$16,198.43	$16,765.38	$17,352.17	$17,959.49	$18,588.07	$19,238.66	$19,912.01	$20,608.93	$21,330.24
FIXED O AND M COST	$000	Wartsila Block x6	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
FIXED O AND M COST	$000	Wartsila Block x6 :2018:700	$0.00	$0.00	$0.00	$0.00	$0.00	$352.38	$364.71	$377.48	$390.69	$404.36	$418.51	$433.16	$448.32	$464.01	$480.25	$497.06	$514.46	$532.47
FIXED O AND M COST	$000	Wartsila Engine	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
FIXED O AND M COST	$000	Wartsila Engine :2018:699	$0.00	$0.00	$0.00	$0.00	$0.00	$143.15	$148.16	$153.35	$158.72	$164.27	$170.02	$175.97	$182.13	$188.51	$195.10	$201.93	$209.00	$216.31
FIXED O AND M COST	$000	Wartsila Engine :2019:698	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$148.16	$153.35	$158.72	$164.27	$170.02	$175.97	$182.13	$188.51	$195.10	$201.93	$209.00	$216.31
FIXED O AND M COST	$000	Wartsila Engine :2021:697	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$158.72	$164.27	$170.02	$175.97	$182.13	$188.51	$195.10	$201.93	$209.00	$216.31
FIXED O AND M COST	$000	Wartsila Engine :2024:696	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$175.97	$182.13	$188.51	$195.10	$201.93	$209.00	$216.31
ANNUAL DEBT SERVICE	$000	Wartsila Block x6 :2018:700						$3,198	$3,198	$3,198	$3,198	$3,198	$3,198	$3,198	$3,198	$3,198	$3,198	$3,198	$3,198	$3,198
ANNUAL DEBT SERVICE	$000	Wartsila Engine :2018:699						$840	$840	$840	$840	$840	$840	$840	$840	$840	$840	$840	$840	$840
ANNUAL DEBT SERVICE	$000	Wartsila Engine :2019:698							$870	$870	$870	$870	$870	$870	$870	$870	$870	$870	$870	$870
ANNUAL DEBT SERVICE	$000	Wartsila Engine :2021:697									$932	$932	$932	$932	$932	$932	$932	$932	$932	$932
ANNUAL DEBT SERVICE	$000	Wartsila Engine :2024:696												$1,033	$1,033	$1,033	$1,033	$1,033	$1,033	$1,033
VARIABLE O AND M COSTS	$/MWH	7FA Combined Cycle Fully Fired (25% ownership)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

Table B-4 CWL CF Gas Sensitivity
Columbia Water and Light
Burns & McDonnell Project No. 67546
2012 IRP

Resource Planning Model Output
Case: CWL 4

Data Item	Units	Description	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
ENERGY COSTS	$/MWH	Ameresco/Columbia LFG	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00
ENERGY COSTS	$/MWH	Blue Grass Ridge	$65.00	$65.00	$65.00	$65.00	$65.00	$65.00	$65.00	$65.00	$65.00	$65.00	$65.00	$65.00	$65.00	$65.00	$65.00	$65.00	$65.00	$65.00
VARIABLE O AND M COSTS	$/MWH	Columbia Energy Center	$1.97	$2.02	$2.07	$2.13	$2.18	$2.23	$2.29	$2.35	$2.40	$2.47	$2.53	$2.59	$2.65	$2.72	$2.79	$2.89	$2.99	$3.09
VARIABLE O AND M COSTS	$/MWH	CWL Unit 5	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$/MWH	CWL Unit 6	$51.62	$53.42	$55.29	$57.23	$59.23	$61.30	$63.45	$65.67	$67.97	$70.35	$72.81	$75.36	$77.99	$80.72	$83.55	$86.47	$89.50	$92.63
VARIABLE O AND M COSTS	$/MWH	CWL Unit 7	$31.35	$32.44	$33.58	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$/MWH	CWL Unit 8	$1.11	$1.15	$1.19	$1.23	$1.27	$1.32	$1.37	$1.41	$1.46	$1.51	$1.57	$1.62	$1.68	$1.74	$1.80	$1.86	$1.93	$1.99
VARIABLE O AND M COSTS	$/MWH	Distributed Generation	$228.06	$236.04	$244.30	$252.85	$261.70	$270.86	$280.34	$290.15	$300.31	$310.82	$321.70	$332.96	$344.61	$356.67	$369.15	$382.07	$395.45	$409.29
ENERGY COSTS	$/MWH	Iatan 2	$17.12	$17.75	$18.46	$19.15	$19.97	$20.77	$21.60	$22.46	$23.36	$24.29	$25.27	$26.28	$27.33	$28.42	$29.56	$30.74	$31.97	$33.25
ENERGY COSTS	$/MWH	Market Capacity	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
ENERGY COSTS	$/MWH	Nearman Creek	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
ENERGY COSTS	$/MWH	NextEra Crystal Lake 3 Wind Farm	$43.50	$44.50	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00
ENERGY COSTS	$/MWH	PPA A	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
ENERGY COSTS	$/MWH	Prairie State Energy Campus	$13.20	$14.30	$14.10	$14.60	$14.70	$15.10	$15.60	$16.00	$16.50	$17.00	$17.50	$18.10	$18.60	$19.20	$19.70	$20.30	$20.90	$21.60
ENERGY COSTS	$/MWH	Sikeston	$24.28	$30.14	$30.97	$31.59	$32.66	$33.60	$34.99	$36.21	$37.48	$38.79	$40.15	$41.55	$43.01	$44.51	$46.07	$47.68	$49.35	$51.08
VARIABLE O AND M COSTS	$/MWH	Wartsila Block x6	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$/MWH	Wartsila Block x6 :2018:700	$0.00	$0.00	$0.00	$0.00	$0.00	$7.50	$7.76	$8.03	$8.31	$8.60	$8.91	$9.22	$9.54	$9.87	$10.22	$10.58	$10.95	$11.33
VARIABLE O AND M COSTS	$/MWH	Wartsila Engine	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$/MWH	Wartsila Engine :2018:699	$0.00	$0.00	$0.00	$0.00	$0.00	$7.50	$7.76	$8.03	$8.31	$8.60	$8.91	$9.22	$9.54	$9.87	$10.22	$10.58	$10.95	$11.33
VARIABLE O AND M COSTS	$/MWH	Wartsila Engine :2019:698	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$7.76	$8.03	$8.31	$8.60	$8.91	$9.22	$9.54	$9.87	$10.22	$10.58	$10.95	$11.33
VARIABLE O AND M COSTS	$/MWH	Wartsila Engine :2021:697	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$8.31	$8.60	$8.91	$9.22	$9.54	$9.87	$10.22	$10.58	$10.95	$11.33
VARIABLE O AND M COSTS	$/MWH	Wartsila Engine :2024:696	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$9.22	$9.54	$9.87	$10.22	$10.58	$10.95	$11.33
VARIABLE O AND M COSTS	$000	7FA Combined Cycle Fully Fired (25% ownership)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
ENERGY COSTS	$000	Ameresco/Columbia LFG	$3,405.89	$3,405.89	$3,405.89	$3,415.22	$3,405.89	$3,405.89	$3,405.89	$3,415.22	$3,405.89	$3,405.89	$3,405.89	$3,415.22	$3,405.89	$3,405.89	$3,405.89	$3,415.22	$3,405.89	$3,405.89
ENERGY COSTS	$000	Blue Grass Ridge	$1,004.42	$1,004.42	$1,004.42	$1,007.17	$1,004.42	$1,004.42	$1,004.42	$1,007.17	$1,004.42	$1,004.42	$1,004.42	$1,007.17	$1,004.42	$1,004.42	$1,004.42	$1,007.17	$1,004.42	$1,004.42
VARIABLE O AND M COSTS	$000	Columbia Energy Center	$189.30	$194.26	$204.15	$211.22	$216.96	$140.79	$114.04	$115.11	$88.40	$92.95	$96.22	$76.33	$76.79	$79.23	$91.32	$96.53	$97.83	$97.97
VARIABLE O AND M COSTS	$000	CWL Unit 5	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$000	CWL Unit 6	$15.08	$15.58	$16.61	$25.24	$26.74	$11.59	$7.94	$8.86	$5.88	$6.23	$7.14	$5.36	$5.92	$6.37	$13.63	$14.07	$15.09	$15.82
VARIABLE O AND M COSTS	$000	CWL Unit 7	$129.64	$137.08	$144.65	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$000	CWL Unit 8	$1.87	$1.88	$2.01	$2.42	$2.53	$1.16	$0.80	$0.85	$0.55	$0.59	$0.66	$0.47	$0.51	$0.55	$1.01	$1.05	$1.10	$1.14
VARIABLE O AND M COSTS	$000	Distributed Generation	$60.96	$63.15	$67.16	$92.25	$98.23	$42.62	$29.29	$33.55	$22.63	$23.88	$27.61	$21.04	$23.38	$25.15	$56.17	$57.80	$62.49	$65.76
ENERGY COSTS	$000	Iatan 2	$2,999.42	$3,109.80	$3,234.19	$3,364.27	$3,498.74	$3,638.90	$3,784.32	$3,945.77	$4,092.67	$4,255.61	$4,427.30	$4,616.87	$4,788.22	$4,979.18	$5,178.91	$5,400.40	$5,601.14	$5,825.40
ENERGY COSTS	$000	Market Capacity	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
ENERGY COSTS	$000	Nearman Creek	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
ENERGY COSTS	$000	NextEra Crystal Lake 3 Wind Farm	$1,800.51	$1,841.90	$1,862.59	$1,867.70	$1,862.59	$1,862.59	$1,862.59	$1,867.70	$1,862.59	$1,862.59	$1,862.59	$1,867.70	$1,862.59	$1,862.59	$1,862.59	$1,867.70	$1,862.59	$1,862.59
ENERGY COSTS	$000	PPA A	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
ENERGY COSTS	$000	Prairie State Energy Campus	$5,203.44	$5,637.06	$5,558.22	$5,771.09	$5,794.74	$5,952.42	$6,149.52	$6,324.48	$6,504.30	$6,701.40	$6,898.50	$7,154.57	$7,332.12	$7,568.64	$7,765.74	$8,024.18	$8,238.78	$8,514.72
ENERGY COSTS	$000	Sikeston	$11,089.80	$13,766.34	$14,145.44	$14,468.15	$14,917.34	$15,439.44	$15,979.82	$16,584.43	$17,117.99	$17,717.11	$18,337.21	$19,031.02	$19,643.28	$20,330.80	$21,042.37	$21,838.53	$22,541.12	$23,330.06
VARIABLE O AND M COSTS	$000	Wartsila Block x6	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$000	Wartsila Block x6 :2018:700	$0.00	$0.00	$0.00	$0.00	$0.00	$159.58	$134.43	$137.40	$113.00	$117.91	$122.27	$102.14	$103.98	$107.81	$119.49	$125.63	$127.70	$128.90
VARIABLE O AND M COSTS	$000	Wartsila Engine	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
VARIABLE O AND M COSTS	$000	Wartsila Engine :2018:699	$0.00	$0.00	$0.00	$0.00	$0.00	$202.98	$171.97	$175.97	$145.00	$151.15	$156.58	$130.71	$133.11	$137.93	$152.47	$160.20	$162.95	$164.68
VARIABLE O AND M COSTS	$000	Wartsila Engine :2019:698	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$218.04	$223.57	$185.50	$193.15	$199.88	$166.94	$169.95	$175.98	$193.78	$203.54	$207.23	$209.64
VARIABLE O AND M COSTS	$000	Wartsila Engine :2021:697	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$235.21	$244.60	$252.89	$212.52	$216.25	$223.73	$244.82	$257.09	$262.10	$265.47
VARIABLE O AND M COSTS	$000	Wartsila Engine :2024:696	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$268.05	$272.72	$281.89	$305.83	$321.00	$327.82	$332.60
TOTAL FUEL COST	$000	7FA Combined Cycle Fully Fired (25% ownership)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL FUEL COST	$000	Ameresco/Columbia LFG	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL FUEL COST	$000	Blue Grass Ridge	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL FUEL COST	$000	Columbia Energy Center	$8,814.84	$9,205.60	$9,664.78	$10,284.45	$10,857.22	$7,205.78	$5,896.99	$6,155.25	$5,019.79	$5,373.52	$5,682.19	$4,568.08	$4,753.40	$5,025.64	$5,756.91	$5,944.67	$5,993.19	$6,118.53
TOTAL FUEL COST	$000	CWL Unit 5	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL FUEL COST	$000	CWL Unit 6	$38.14	$39.81	$42.00	$64.55	$69.50	$31.00	$21.49	$24.62	$17.34	$18.80	$21.65	$16.26	$18.53	$20.16	$41.53	$41.85	$44.69	$47.84
TOTAL FUEL COST	$000	CWL Unit 7	$315.87	$329.26	$339.72	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL FUEL COST	$000	CWL Unit 8	$167.25	$169.20	$179.17	$222.26	$237.20	$110.67	$77.16	$83.58	$57.55	$62.75	$70.43	$51.13	$56.69	$61.53	$110.28	$112.21	$117.19	$123.49
TOTAL FUEL COST	$000	Distributed Generation	$60.44	$62.61	$66.61	$91.43	$97.35	$42.36	$29.16	$33.40	$22.57	$23.82	$27.50	$20.96	$23.28	$25.02	$55.74	$57.35	$61.99	$65.19
TOTAL FUEL COST	$000	Iatan 2	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL FUEL COST	$000	Market Capacity	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL FUEL COST	$000	Nearman Creek	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL FUEL COST	$000	NextEra Crystal Lake 3 Wind Farm	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL FUEL COST	$000	PPA A	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL FUEL COST	$000	Prairie State Energy Campus	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL FUEL COST	$000	Sikeston	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL FUEL COST	$000	Wartsila Block x6	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL FUEL COST	$000	Wartsila Block x6 :2018:700	$0.00	$0.00	$0.00	$0.00	$0.00	$1,677.49	$1,413.97	$1,479.74	$1,265.32	$1,346.12	$1,412.01	$1,184.54	$1,233.72	$1,297.92	$1,415.76	$1,454.01	$1,469.46	$1,511.34
TOTAL FUEL COST	$000	Wartsila Engine	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
TOTAL FUEL COST	$000	Wartsila Engine :2018:699	$0.00	$0.00	$0.00	$0.00	$0.00	$2,133.04	$1,808.33	$1,894.54	$1,623.34	$1,725.16	$1,807.76	$1,515.82	$1,578.98	$1,660.22	$1,805.93	$1,853.54	$1,874.53	$1,930.12
TOTAL FUEL COST	$000	Wartsila Engine :2019:698	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$2,292.01	$2,406.19	$2,076.14	$2,203.75	$2,306.91	$1,935.72	$2,015.45	$2,117.52	$2,294.41	$2,354.13	$2,383.09	$2,456.09
TOTAL FUEL COST	$000	Wartsila Engine :2021:697	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$2,631.38	$2,789.58	$2,917.41	$2,463.69	$2,563.56	$2,691.13	$2,897.65	$2,972.22	$3,012.84	$3,108.87
TOTAL FUEL COST	$000	Wartsila Engine :2024:696	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$3,106.53	$3,231.52	$3,389.15	$3,618.39	$3,709.73	$3,766.77	$3,893.48
TOTAL VARIABLE COST	$/MWH	7FA Combined Cycle Fully Fired (25% ownership)																		
TOTAL ENERGY COSTS	$/MWH	Ameresco/Columbia LFG	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00	$60.00
TOTAL ENERGY COSTS	$/MWH	Blue Grass Ridge	$65.00	$65.00	$65.00	$65.00	$65.00	$65.00	$65.00	$65.00	$65.00	$65.00	$65.00	$65.00	$65.00	$65.00	$65.00	$65.00	$65.00	$65.00
TOTAL VARIABLE COST	$/MWH	Columbia Energy Center	$93.88	$97.89	$100.25	$105.62	$111.21	$116.53	$120.66	$127.81	$137.43	$144.97	$151.74	$157.59	$166.97	$175.30	$178.61	$180.65	$186.01	$196.20
TOTAL VARIABLE COST	$/MWH	CWL Unit 5																		
TOTAL VARIABLE COST	$/MWH	CWL Unit 6	$182.18	$189.92	$195.12	$203.61	$213.20	$225.19	$235.13	$248.18	$268.44	$282.66	$293.66	$304.06	$322.29	$336.37	$338.08	$343.75	$354.55	$372.73
TOTAL VARIABLE COST	$/MWH	CWL Unit 7	$107.72	$110.37	$112.43															
TOTAL VARIABLE COST	$/MWH	CWL Unit 8	$100.64	$104.91	$107.43	$114.60	$120.62	$127.45	$132.83	$141.19	$153.89	$162.70	$168.91	$176.28	$188.24	$197.28	$198.67	$200.83	$207.02	$218.81
TOTAL VARIABLE COST	$/MWH	Distributed Generation	$454.14	$470.09	$486.59	$503.45	$521.06	$540.07	$559.41	$578.98	$599.89	$620.84	$642.19	$664.59	$687.79	$711.55	$735.47	$761.22	$787.75	$815.02
TOTAL ENERGY COSTS	$/MWH	Iatan 2	$17.12	$17.75	$18.46	$19.15	$19.97	$20.77	$21.60	$22.46	$23.36	$24.29	$25.27	$26.28	$27.33	$28.42	$29.56	$30.74	$31.97	$33.25
TOTAL ENERGY COSTS	$/MWH	Market Capacity																		
TOTAL ENERGY COSTS	$/MWH	Nearman Creek																		
TOTAL ENERGY COSTS	$/MWH	NextEra Crystal Lake 3 Wind Farm	$43.50	$44.50	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00	$45.00

Table B-4 CWL CF Gas Sensitivity
Columbia Water and Light
Burns & McDonnell Project No. 67546
2012 IRP

Resource Planning Model Output
Case: CWL 4

Data Item	Units	Description	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
TOTAL ENERGY COSTS	$/MWH	PPA A																		
TOTAL ENERGY COSTS	$/MWH	Prairie State Energy Campus	$13.20	$14.30	$14.10	$14.60	$14.70	$15.10	$15.60	$16.00	$16.50	$17.00	$17.50	$18.10	$18.60	$19.20	$19.70	$20.30	$20.90	$21.60
TOTAL ENERGY COSTS	$/MWH	Sikeston	$24.28	$30.14	$30.97	$31.59	$32.66	$33.80	$34.99	$36.21	$37.48	$38.79	$40.15	$41.55	$43.01	$44.51	$46.07	$47.68	$49.35	$51.08
TOTAL VARIABLE COST	$/MWH	Wartsila Block x6																		
TOTAL VARIABLE COST	$/MWH	Wartsila Block x6 2018:700						$86.32	$89.39	$94.54	$101.41	$106.84	$111.75	$116.12	$122.73	$128.75	$131.30	$132.99	$136.92	$144.18
TOTAL VARIABLE COST	$/MWH	Wartsila Engine																		
TOTAL VARIABLE COST	$/MWH	Wartsila Engine :2018:699						$86.30	$89.37	$94.51	$101.39	$106.81	$111.73	$116.12	$122.71	$128.73	$131.27	$132.96	$136.89	$144.13
TOTAL VARIABLE COST	$/MWH	Wartsila Engine :2019:698							$89.34	$94.48	$101.36	$106.78	$111.69	$116.10	$122.68	$128.69	$131.22	$132.91	$136.84	$144.08
TOTAL VARIABLE COST	$/MWH	Wartsila Engine :2021:697									$101.32	$106.74	$111.64	$116.07	$122.64	$128.64	$131.18	$132.86	$136.79	$144.02
TOTAL VARIABLE COST	$/MWH	Wartsila Engine :2024:696												$116.04	$122.58	$128.59	$131.13	$132.82	$136.74	$143.97
SYSTEM EFFLUENT EXPENSE	$000	NOx	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
SYSTEM EFFLUENT EXPENSE	$000	CO2	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
SYSTEM EFFLUENT EXPENSE	$000	SO2	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
SYSTEM EFFLUENT EXPENSE	$000	Hg	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
SYSTEM EFFLUENT EXPENSE	$000	CO	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
SUMMARY OF COSTS																				
TOTAL FIXED COSTS	$000		$15,863	$16,299	$16,747	$15,579	$15,996	$17,268	$17,882	$18,367	$19,023	$19,541	$20,072	$20,794	$21,362	$21,946	$22,545	$23,056	$23,863	$24,698
TOTAL VARIABLE (EXCL. FUEL) COSTS	$000		$7,960	$9,206	$10,342	$11,680	$13,567	$14,703	$16,431	$18,770	$21,238	$24,508	$27,734	$30,469	$34,435	$37,411	$39,980	$42,792	$46,280	$50,611
TOTAL FUEL COSTS	$000		$9,397	$9,806	$10,292	$10,663	$11,261	$11,200	$11,539	$12,077	$12,713	$13,544	$14,246	$14,863	$15,475	$16,288	$17,997	$18,500	$18,724	$19,255
TOTAL DEBT SERVICE COSTS	$000		$0	$0	$0	$0	$0	$4,038	$4,908	$4,908	$5,840	$5,840	$5,840	$6,873	$6,873	$6,873	$6,873	$6,873	$6,873	$6,873
TOTAL PURCHASE COSTS	$000		$62,681	$67,980	$67,203	$66,728	$66,746	$67,966	$69,957	$72,093	$74,091	$76,523	$79,086	$81,585	$84,227	$87,064	$90,013	$93,273	$96,319	$99,687
TOTAL COSTS	$000		$95,900	$103,292	$104,585	$104,650	$107,570	$115,176	$120,717	$126,216	$132,905	$139,954	$146,979	$154,585	$162,372	$169,582	$177,408	$184,494	$192,059	$201,124

NPV @ 4.0% ($000): $1,703,830

APPENDIX C

DSM LOAD IMPACT DETAILS

Table C-1 Historical DSM Program Demand and Energy Savings

	Historial Participation and Demand/Energy Savings										Strategist Data				
	Current Participation	Current Participation Percentage	Total MW Reduction	Total MW Reduction / Installation	Total MWh Reduction	Total MWh Reduction / Installation	Program Cost	Differential Cost / Installation	$/MW	$/kWh	$/MW $383,173.34	$/MWh $494.12			
											Avoided Demand Cost ($)	Avoided Energy Cost ($)	Total Avoided Cost ($)	Continue Program	Program Savings
RESIDENTIAL															
Home Performance with Energy Star															
2010	607	2.57%	0.173	0.0003	570	0.940	$233,473	$384.63	$1,349,554.91	$409.31	$66,289	$281,845	$348,134	yes	$114,661
2011	906	3.84%	0.245	0.0003	843	0.930	$515,369	$568.84	$2,103,546.94	$611.66	$93,877	$416,334	$510,211	no	($5,158)
Total	1,513	6.40%	0.418	0.0003	1,413	0.934	$748,842	$494.94	$1,791,488.04	$529.97	$160,166	$698,178	$858,345	yes	$109,503
Air Conditioner or Heat Pump Rebates															
2010	192	0.81%	0.112	0.0006	289	1.504	$65,500	$341.15	$584,821.43	$226.80	$42,915	$142,701	$185,617	yes	$120,117
2011	368	1.56%	0.133	0.0004	564	1.532	$141,230	$383.78	$1,061,879.70	$250.51	$50,962	$278,572	$329,534	yes	$188,304
Total	560	2.37%	0.245	0.0004	853	1.522	$206,730	$369.16	$843,795.92	$242.48	$93,877	$421,273	$515,150	yes	$308,420
Online Energy Audit															
2010	1,396	5.91%	0.000	0.0000	377	0.270	$0	$0.00	$0.00	$0.00	$0	$186,243	$186,243	yes	$186,243
2011	605	2.56%	0.000	0.0000	163	0.270	$8,260	$13.65	$0.00	$50.57	$0	$80,714	$80,714	yes	$72,454
Total	2,001	8.47%	0.000	0.0000	540	0.270	$8,260	$4.13	$0.00	$15.29	$0	$266,957	$266,957	yes	$258,697
Energy Audits															
2010	276	1.17%	0.000	0.0000	317	1.147	$0	$0.00	$0.00	$0.00	$0	$156,418	$156,418	yes	$156,418
2011	576	2.44%	0.000	0.0000	105	0.183	$0	$0.00	$0.00	$0.00	$0	$52,006	$52,006	yes	$52,006
Total	852	3.61%	0.000	0.0000	422	0.495	$0	$0.00	$0.00	$0.00	$0	$208,424	$208,424	yes	$208,424
Tree Power & Landscape Audit															
2010	98	0.41%	0.005	0.0000	33	0.340	$7,840	$80.00	$1,633,333.33	$235.11	$1,839	$16,477	$18,316	yes	$10,476
2011	98	0.41%	0.002	0.0000	102	1.042	$7,400	$75.51	$4,933,333.33	$72.49	$575	$50,442	$51,017	yes	$43,617
Total	196	0.83%	0.006	0.0000	135	0.691	$15,240	$77.76	$2,419,047.62	$112.53	$2,414	$66,919	$69,333	yes	$54,093
Window Air Conditioner Exchange Program															
2010	125	0.53%	0.063	0.0005	91	0.730	$22,950	$183.60	$367,200.00	$251.51	$23,948	$45,088	$69,037	yes	$46,087
2011	30	0.13%	0.000	0.0000	22	0.730	$0	$0.00	$0.00	$0.00	$0	$10,821	$10,821	yes	$10,821
Total	155	0.66%	0.063	0.0004	113	0.730	$22,950	$148.06	$367,200.00	$202.83	$23,948	$55,909	$79,858	yes	$56,908
Total Residential Programs	-84 2,583	-0.36% 10.93%	0.732		3,476		$1,002,022		$1,369,256.63	$288.25	$280,406	$1,717,660	$1,998,066	yes	
COMMERCIAL															
Lighting Incentive Program															
2010	11	0.17%	0.185	0.02	648	58.91	$23,809	$2,164.45	$128,697.30	$36.74	$70,887	$320,188	$391,075	yes	$367,266
2011	50	0.79%	0.460	0.01	1,449	28.98	$127,407	$2,548.14	$276,971.74	$87.93	$176,260	$715,923	$892,183	yes	$764,776
2012	68	1.08%	0.636	0.01	1,943	28.57	$161,181	$2,370.31	$253,429.25	$82.96	$243,698	$960,036	$1,203,734	yes	$1,042,553
Total	129	2.04%	1.281	0.01	4,040	31.32	$312,397	$2,421.68	$243,869.63	$77.33	$490,845	$1,996,147	$2,486,992	yes	$2,174,595
HVAC															
2012	13	0.21%	0.058	0.00	100	7.73	$282,350	$21,719.23	$4,868,103.45	$2,810.38	$22,224	$49,643	$71,867	no	($210,483)
Total	13	0.21%	0.058	0.00	100	7.73	$282,350	$21,719.23	$4,868,103.45	$2,810.38	$22,224	$49,643	$71,867	no	($210,483)
Total Commercial Programs			1.339		4,140		$594,747		$444,172.52	$143.65	$513,069	$2,045,789	$2,558,859	yes	$1,964,112
Total All Programs			2.071		7,617		$1,596,769		$771,087.99	$209.65	$793,475	$3,763,450	$4,556,925	yes	$2,960,156

[1] Contractor Incentives are not included in the table above. These costs are marketing costs creating market transformation.
The incentives will be diminished when the market for the service is mature and the data reporting is automatic.
Contractor incentives were $318,000 in FY2010 and $412,000 in FY2011.

Table C-2 Projected Residential Energy and Demand Savings by DSM Program

	Avg kWh Reduction	Avg kW Reduction	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	Total Participation
Home Performance with Energy Star													
Houses Built Before 1970	930	0.28	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	50.0%
Annual Energy Savings (kWh)			307,644	307,644	307,644	307,644	307,644	307,644	307,644	307,644	307,644	307,644	
Aggregate Energy Savings (kWh)			307,644	615,288	922,932	1,230,576	1,538,220	1,845,864	2,153,508	2,461,152	2,768,796	3,076,440	
Annual Demand Savings (kW)			93	93	93	93	93	93	93	93	93	93	
Aggregate Demand Savings (kW)			93	185	278	370	463	556	648	741	834	926	
Houses Built Between 1970 -1989	930	0.28	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	25.0%
Annual Energy Savings (kWh)			74,981	74,981	74,981	74,981	74,981	74,981	74,981	74,981	74,981	74,981	
Aggregate Energy Savings (kWh)			74,981	149,963	224,944	299,925	374,906	449,888	524,869	599,850	674,831	749,813	
Annual Demand Savings (kW)			23	23	23	23	23	23	23	23	23	23	
Aggregate Demand Savings (kW)			23	45	68	90	113	135	158	181	203	226	
Houses Built from 1990 to Present	930	0.28	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	10.0%
Annual Energy Savings (kWh)			112,195	112,195	112,195	112,195	112,195	112,195	112,195	112,195	112,195	112,195	
Aggregate Energy Savings (kWh)			112,195	224,390	336,586	448,781	560,976	673,171	785,366	897,562	1,009,757	1,121,952	
Annual Demand Savings (kW)			34	34	34	34	34	34	34	34	34	34	
Aggregate Demand Savings (kW)			34	68	101	135	169	203	236	270	304	338	
New Houses	930	0.28	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	5.0%
Annual Energy Savings (kWh)			1,019	1,029	1,039	1,049	1,060	1,071	1,081	1,092	1,103	1,114	
Aggregate Energy Savings (kWh)			1,019	2,047	3,086	4,136	5,196	6,266	7,348	8,440	9,543	10,657	
Annual Demand Savings (kW)			0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	
Aggregate Demand Savings (kW)			0	1	1	1	2	2	2	3	3	3	
Total Participation			2.4%	2.4%	2.4%	2.3%	2.3%	2.3%	2.3%	2.2%	2.2%	2.2%	23.1%
Total Annual Energy Reduction (kWh)			495,839	495,849	495,860	495,870	495,880	495,891	495,902	495,913	495,923	495,934	
Total Aggregate Energy Reduction (MWh)			496	992	1,488	1,983	2,479	2,975	3,471	3,967	4,463	4,959	
Total Annual Demand Reduction (kW)			149	149	149	149	149	149	149	149	149	149	
Total Aggregate Demand Reduction (kW)			0.149	0.299	0.448	0.597	0.746	0.896	1.045	1.194	1.344	1.493	
Air Conditioner or Heat Pump Rebates													
Houses Built Before 1970	1,520	0.44	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	20.0%
Annual Energy Savings (kWh)			201,126	201,126	201,126	201,126	201,126	201,126	201,126	201,126	201,126	201,126	
Aggregate Energy Savings (kWh)			201,126	402,253	603,379	804,506	1,005,632	1,206,758	1,407,885	1,609,011	1,810,138	2,011,264	
Annual Demand Savings (kW)			58	58	58	58	58	58	58	58	58	58	
Aggregate Demand Savings (kW)			58	116	175	233	291	349	408	466	524	582	
Houses Built Between 1970 -1989	1,520	0.44	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	1.5%	15.0%
Annual Energy Savings (kWh)			73,530	73,530	73,530	73,530	73,530	73,530	73,530	73,530	73,530	73,530	
Aggregate Energy Savings (kWh)			73,530	147,060	220,590	294,120	367,650	441,180	514,710	588,240	661,770	735,300	
Annual Demand Savings (kW)			21	21	21	21	21	21	21	21	21	21	
Aggregate Demand Savings (kW)			21	43	64	85	106	128	149	170	192	213	
Houses Built from 1990 to Present	1,520	0.44	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	1.0%	10.0%
Annual Energy Savings (kWh)			183,373	183,373	183,373	183,373	183,373	183,373	183,373	183,373	183,373	183,373	
Aggregate Energy Savings (kWh)			183,373	366,746	550,118	733,491	916,864	1,100,237	1,283,610	1,466,982	1,650,355	1,833,728	
Annual Demand Savings (kW)			53	53	53	53	53	53	53	53	53	53	
Aggregate Demand Savings (kW)			53	106	159	212	265	318	372	425	478	531	
New Houses	1,520	0.44	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Annual Energy Savings (kWh)			0	0	0	0	0	0	0	0	0	0	
Aggregate Energy Savings (kWh)			0	0	0	0	0	0	0	0	0	0	
Annual Demand Savings (kW)			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Aggregate Demand Savings (kW)			0	0	0	0	0	0	0	0	0	0	
Total Participation			1.4%	1.3%	1.3%	1.3%	1.3%	1.3%	1.3%	1.3%	1.3%	1.2%	13.0%
Total Annual Reduction			458,029	458,029	458,029	458,029	458,029	458,029	458,029	458,029	458,029	458,029	
Total Aggregate Energy Reduction (MWh)			458	916	1,374	1,832	2,290	2,748	3,206	3,664	4,122	4,580	
Total Annual Demand Reduction (kW)			133	133	133	133	133	133	133	133	133	133	
Total Aggregate Demand Reduction (kW)			0.133	0.265	0.398	0.530	0.663	0.796	0.928	1.061	1.193	1.326	
Online Energy Audit													
Houses Built Before 1970	270	0.00	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	50.0%
Annual Energy Savings (kWh)			89,316	89,316	89,316	89,316	89,316	89,316	89,316	89,316	89,316	89,316	
Aggregate Energy Savings (kWh)			89,316	178,632	267,948	357,264	446,580	535,896	625,212	714,528	803,844	893,160	
Annual Demand Savings (kW)			0	0	0	0	0	0	0	0	0	0	
Aggregate Demand Savings (kW)			0	0	0	0	0	0	0	0	0	0	
Houses Built Between 1970 -1989	270	0.00	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	50.0%
Annual Energy Savings (kWh)			43,538	43,538	43,538	43,538	43,538	43,538	43,538	43,538	43,538	43,538	
Aggregate Energy Savings (kWh)			43,538	87,075	130,613	174,150	217,688	261,225	304,763	348,300	391,838	435,375	
Annual Demand Savings (kW)			0	0	0	0	0	0	0	0	0	0	
Aggregate Demand Savings (kW)			0	0	0	0	0	0	0	0	0	0	
Houses Built from 1990 to Present	270	0.00	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	2.0%	20.0%
Annual Energy Savings (kWh)			65,146	65,146	65,146	65,146	65,146	65,146	65,146	65,146	65,146	65,146	
Aggregate Energy Savings (kWh)			65,146	130,291	195,437	260,582	325,728	390,874	456,019	521,165	586,310	651,456	
Annual Demand Savings (kW)			0	0	0	0	0	0	0	0	0	0	
Aggregate Demand Savings (kW)			0	0	0	0	0	0	0	0	0	0	
New Houses	270	0.00	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Annual Energy Savings (kWh)			0	0	0	0	0	0	0	0	0	0	
Aggregate Energy Savings (kWh)			0	0	0	0	0	0	0	0	0	0	
Annual Demand Savings (kW)			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Aggregate Demand Savings (kW)			0	0	0	0	0	0	0	0	0	0	
Total Participation			3.3%	3.3%	3.2%	3.2%	3.2%	3.2%	3.1%	3.1%	3.1%	3.0%	31.7%
Total Annual Reduction			197,999	197,999	197,999	197,999	197,999	197,999	197,999	197,999	197,999	197,999	
Total Aggregate Energy Reduction (MWh)			198	396	594	792	990	1,188	1,386	1,584	1,782	1,980	
Total Annual Demand Reduction (kW)			0	0	0	0	0	0	0	0	0	0	
Total Aggregate Demand Reduction (kW)			0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	
Tree Power & Landscape Audit													
Houses Built Before 1970	600	0.03	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Annual Energy Savings (kWh)			0	0	0	0	0	0	0	0	0	0	
Aggregate Energy Savings (kWh)			0	0	0	0	0	0	0	0	0	0	
Annual Demand Savings (kW)			0	0	0	0	0	0	0	0	0	0	
Aggregate Demand Savings (kW)			0	0	0	0	0	0	0	0	0	0	
Houses Built Between 1970 -1989	600	0.03	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Annual Energy Savings (kWh)			0	0	0	0	0	0	0	0	0	0	
Aggregate Energy Savings (kWh)			0	0	0	0	0	0	0	0	0	0	
Annual Demand Savings (kW)			0	0	0	0	0	0	0	0	0	0	
Aggregate Demand Savings (kW)			0	0	0	0	0	0	0	0	0	0	
Houses Built from 1990 to Present	600	0.03	0.9%	0.9%	0.9%	0.9%	0.9%	0.9%	0.9%	0.9%	0.9%	0.9%	9.0%
Annual Energy Savings (kWh)			65,146	65,146	65,146	65,146	65,146	65,146	65,146	65,146	65,146	65,146	
Aggregate Energy Savings (kWh)			65,146	130,291	195,437	260,582	325,728	390,874	456,019	521,165	586,310	651,456	
Annual Demand Savings (kW)			3	3	3	3	3	3	3	3	3	3	
Aggregate Demand Savings (kW)			3	7	10	13	16	20	23	26	29	33	
New Houses	600	0.03	0.8%	0.8%	0.8%	0.8%	0.8%	0.8%	0.8%	0.8%	0.8%	0.8%	8.0%
Annual Energy Savings (kWh)			1,051	1,062	1,073	1,083	1,094	1,105	1,116	1,127	1,139	1,150	
Aggregate Energy Savings (kWh)			1,051	2,113	3,186	4,269	5,363	6,468	7,585	8,712	9,850	11,000	
Annual Demand Savings (kW)			0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	
Aggregate Demand Savings (kW)			0	0	0	0	0	0	0	0	0	1	
Total Participation			0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	4.8%
Total Annual Reduction			66,197	66,208	66,218	66,229	66,240	66,251	66,262	66,273	66,284	66,296	
Total Aggregate Energy Reduction (MWh)			66	132	199	265	331	397	464	530	596	662	
Total Annual Demand Reduction (kW)			3	3	3	3	3	3	3	3	3	3	
Total Aggregate Demand Reduction (kW)			0.003	0.007	0.010	0.013	0.017	0.020	0.023	0.026	0.030	0.033	
Window Air Conditioner Exchange Program													
Houses Built Before 1970	730	0.40	0.9%	0.9%	0.9%	0.9%	0.9%	0.9%	0.9%	0.9%	0.9%	0.9%	9.0%
Annual Energy Savings (kWh)			43,467	43,467	43,467	43,467	43,467	43,467	43,467	43,467	43,467	43,467	
Aggregate Energy Savings (kWh)			43,467	86,934	130,401	173,868	217,336	260,803	304,270	347,737	391,204	434,671	
Annual Demand Savings (kW)			24	24	24	24	24	24	24	24	24	24	
Aggregate Demand Savings (kW)			24	48	71	95	119	143	167	191	214	238	
Houses Built Between 1970 -1989	730	0.40	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	0.5%	4.5%
Annual Energy Savings (kWh)			10,594	10,594	10,594	10,594	10,594	10,594	10,594	10,594	10,594	10,594	
Aggregate Energy Savings (kWh)			10,594	21,188	31,782	42,377	52,971	63,565	74,159	84,753	95,347	105,941	
Annual Demand Savings (kW)			6	6	6	6	6	6	6	6	6	6	
Aggregate Demand Savings (kW)			6	12	17	23	29	35	41	46	52	58	
Houses Built from 1990 to Present	730	0.40	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	0.1%	1.0%
Annual Energy Savings (kWh)			8,807	8,807	8,807	8,807	8,807	8,807	8,807	8,807	8,807	8,807	
Aggregate Energy Savings (kWh)			8,807	17,613	26,420	35,227	44,034	52,840	61,647	70,454	79,260	88,067	
Annual Demand Savings (kW)			5	5	5	5	5	5	5	5	5	5	
Aggregate Demand Savings (kW)			5	10	14	19	24	29	34	39	43	48	
New Houses	730	0.40	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Annual Energy Savings (kWh)			0	0	0	0	0	0	0	0	0	0	
Aggregate Energy Savings (kWh)			0	0	0	0	0	0	0	0	0	0	
Annual Demand Savings (kW)			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Aggregate Demand Savings (kW)			0	0	0	0	0	0	0	0	0	0	
Total Participation			0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	3.7%
Total Annual Reduction			62,868	62,868	62,868	62,868	62,868	62,868	62,868	62,868	62,868	62,868	
Total Aggregate Energy Reduction (MWh)			63	126	189	251	314	377	440	503	566	629	
Total Annual Demand Reduction (kW)			34	34	34	34	34	34	34	34	34	34	
Total Aggregate Demand Reduction (kW)			0.034	0.069	0.103	0.138	0.172	0.207	0.241	0.276	0.310	0.344	

Table C-3 Projected Commercial Energy and Demand Savings by DSM Program

	Avg kWh Reduction	Avg kW Reduction	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	Total Participation
Lighting Incentive Program													
Participation Level	**30,000**	**9.93**	**0.6%**	**0.6%**	**0.6%**	**0.6%**	**0.6%**	**0.6%**	**0.6%**	**0.6%**	**0.6%**	**0.6%**	6.0%
Annual Energy Savings (kWh)			1,140,805	1,143,657	1,146,516	1,149,382	1,152,256	1,155,136	1,158,024	1,160,919	1,163,822	1,166,731	
Aggregate Energy Savings (MWh)			1,141	2,284	3,431	4,580	5,733	6,888	8,046	9,207	10,371	11,537	
Annual Demand Savings (kW)			378	379	379	380	381	382	383	384	385	386	
Aggregate Demand Savings (kW)			0.378	0.756	1.136	1.516	1.897	2.280	2.663	3.047	3.433	3.819	
HVAC													
Participation Level	**22,404**	**9.47**	**0.2%**	**0.2%**	**0.2%**	**0.2%**	**0.2%**	**0.2%**	**0.2%**	**0.2%**	**0.2%**	**0.2%**	2.1%
Annual Energy Savings (kWh)			291,980	292,710	293,442	294,175	294,911	295,648	296,387	297,128	297,871	298,616	
Aggregate Energy Savings (MWh)			292	585	878	1,172	1,467	1,763	2,059	2,356	2,654	2,953	
Annual Demand Savings (kW)			123	124	124	124	125	125	125	126	126	126	
Aggregate Demand Savings (kW)			0.123	0.247	0.371	0.496	0.620	0.745	0.870	0.996	1.122	1.248	