Initially, GMO wanted to allocate the investment and costs of all 153 MW of GMO's share of Iatan 2 to MPS. This would have given MPS some fuel and purchased power expense stability, and diversified MPS's generation portfolio. Staff and other stakeholders voiced their concerns about allocating all of Iatan 2 to GMO. Iatan 2 was, and is, likely to be one of the last coal plants built in the Midwest for quite some time due to uncertainty regarding potential federal emissions restrictions. Absent its merger with SJLP, which owned 18% of Iatan 1, it is unlikely that GMO could have acquired any ownership of Iatan 2. In addition, L&P needed additional capacity to replace L&P's base load contract with NPPD that would end soon after Iatan 2 was planned to come on line.

When Staff expressed its concerns regarding GMO's intent to allocate all of Iatan 2 to MPS, Aquila committed to Staff that it would work with stakeholders to develop a methodology to allocate Iatan 2 between MPS and L&P.

Staff also expressed its concerns regarding the allocation of Iatan 2 to Great Plains Energy, Inc. ("GPE") when GPE requested authorization from the Commission to acquire GMO (then named Aquila). Again, GPE assured Staff that it understood Staff's concerns and committed to work with stakeholders to develop a methodology for allocating Iatan 2 between MPS and L&P. After GPE acquired GMO, GMO again assured Staff that it was working on an allocation methodology and that it would share that methodology with Staff and other stakeholders.

Despite all these assurances by GPE and GMO, which started before construction of Iatan 2 began, that GMO would work with Staff to develop an appropriate allocation of Iatan 2 investment and costs between MPS and L&P, GMO's direct testimony filing in this case is the first time that GMO has presented a proposed allocation of Iatan 2 investment and costs between MPS and L&P.

Since separate resource plans do not exist for MPS and L&P and GMO did not work with stakeholders to determine an appropriate allocation of Iatan 2 investment and costs to MPS and L&P, Staff considered several factors when determining its proposed allocation. These factors include:

1. The capacity needs of MPS and L&P
2. The ownership "rights" to Iatan 2
3. The impact on customer rates

Staff examined five different allocation scenarios in its analysis of how to allocate Iatan 2. These scenarios are:

Scenario 1: All 153 MW to L&P

Scenario 2: 100 MW to L&P and 53 MW to MPS

Scenario 3: 53 MW to L&P and 100 MW to MPS

Scenario 4: GMO's position of 41 MW to L&P and 112 MW to MPS

Scenario 5: All 153 MW to MPS

A detailed discussion of the factors Staff considered, along with the scenario Staff finds most appropriate, follows.

<u>The Capacity Needs of MPS and L&P</u>

Because separate resource plan studies are not available for MPS and L&P, Staff does not know GMO's exact needs to separately serve its MPS and L&P customers. The capacity needs of MPS and L&P that Staff has previously discussed in this Report are based on Staff's knowledge of resource planning, the generation plant characteristics and loads of MPS and L&P when GMO and SJLP merged in 2000, and GMO's current resource plans.

With these limits, if MPS were a standalone utility, it would be very beneficial for MPS to diversify its generation portfolio with base load capacity. In addition, MPS likely will need more capacity, if not in 2010, soon after. The lower fuel cost of base load capacity would also likely stabilize MPS's fuel costs. Scenario 5 above, all of Iatan 2 allocated to MPS, would be the most appropriate scenario, if the only consideration is MPS's needs as a standalone utility.

If L&P were a stand-alone utility, it would need to replace the 100 MW NPPD PPA that ends in May 2011. Since the NPPD PPA is a base load contract, it would be logical for L&P to replace it with base load capacity. It would also be logical, since L&P already has so much base load capacity, that L&P instead add lower capital cost peaking capacity rather than base load capacity. But, since the opportunity to own a portion of another base load unit in the Midwest is not likely to occur in the near future, and given that L&P could sell excess energy on the market, L&P, as it did when it invested in Iatan 1, may have chosen to add more base load. Scenarios 1, 2 and 3 are reasonable for GMO if the only consideration is L&P's needs as a stand alone utility.

<u>Ownership Rights to Iatan 2</u>

GMO obtained ownership of Iatan 1 by merging with St. Joseph Light & Power Company. If they had not merged, given GMO's poor financial condition when KCPL was looking for potential partners for Iatan 2, KCPL would not have considered GMO as a potential partner.

If ownership rights were the only factor considered for allocating Iatan 2, then all of GMO's portion of Iatan 2 would be allocated to L&P. Therefore Scenario 1 would be appropriate, if the only consideration is the source of ownership rights to Iatan 2.

Impact on Rates

The capital investment in Iatan 2, a base load plant, is very high. However the impact on revenue requirement due to capital investment should not be considered alone when determining the revenue requirement impacts of Iatan 2. Because Iatan 2 is expected to be the most efficient unit and to have the lowest running cost of all of GMO's generating resources, the revenue requirement impacts due to the reduction of fuel and purchased power costs associated with Iatan 2 should also be considered. Integral to the current methodology of allocating fuel costs to MPS and L&P is the assignment of power plants to either MPS or L&P. A history and description of the fuel allocation methodology can be found on Appendix 5, Schedule LMM-4.

The fuel cost to MPS is minimized when all of Iatan 2 is allocated to MPS. And the same is true for L&P when all of Iatan 2 is allocated to L&P. Therefore the net fuel cost impact on either MPS or L&P is the difference between the fuel cost of each scenario minus the fuel cost of the scenario where all of Iatan 2 is allocated either to MPS or to L&P. In addition, the net impact on L&P is less than GMO's capital investment and costs of Iatan 2 since L&P will no longer have to pay the NPPD PPA capacity costs that L&P have been paying since 1996. The non-fuel net cost to L&P is the difference between the revenue requirement due to the capital investment and costs of Iatan 2 and the NPPD PPA capacity costs.

To get a feel for the total revenue requirement impacts on MPS and L&P, Staff calculated the Iatan 2 revenue requirement[42] for MPS and L&P for the scenarios listed above. Staff's fuel and purchased power allocation methodology described in Appendix 5, Schedule LMM- 4 was applied to the results of Staff's fuel run model[43] for each of the five scenarios to calculate the

[42] Fixed charges and depreciation at Staff mid-point ROR of 7.98%. Does not include fuel, non-wage O&M, wage, insurance, property taxes

[43] Staff's fuel run model with Iatan 2, without Crossroads, with Prudent CTs 4 & 5, without NPPD PPA, and with December 2010 estimated fuel prices.

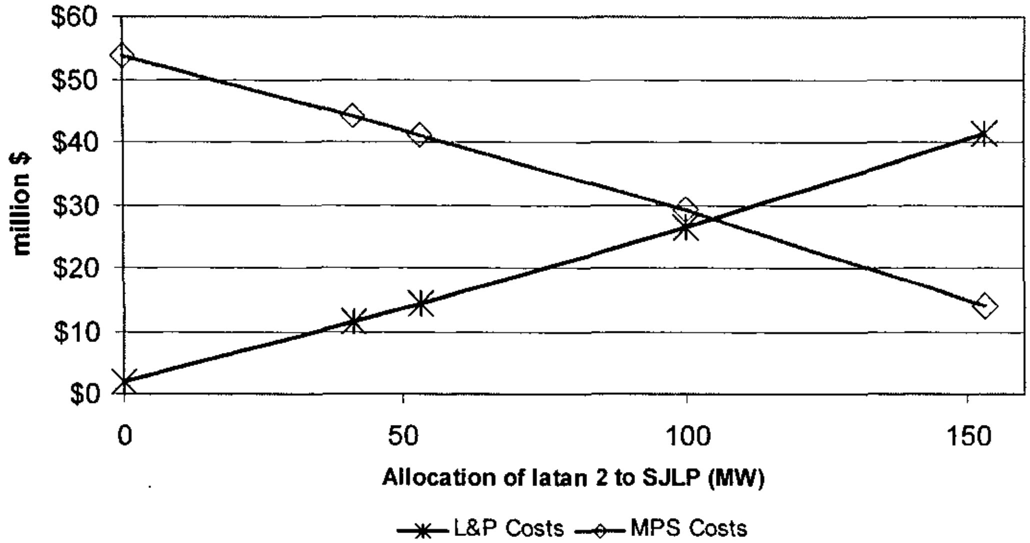
difference in the fuel costs for MPS and L&P for each of the five scenarios. From these results Staff was able to estimate the impact of Iatan 2 on fuel costs. The total impacts on MPS and L&P and the percent of current revenues for each are shown in the tables below.

MPS				
Scenario	**Capital Costs**	**Change in Fuel Costs**	**Total**	**% of Current Revenue**
1	$0	$14,115,884	$14,115,884	2.6%
2	$18,645,319	$10,532,214	$29,177,533	5.3%
3	$35,180,760	$6,079,896	$41,260,656	7.5%
4	$39,401,433	$4,764,849	$44,166,282	8.0%
5	$53,825,174	$0	$53,825,174	9.8%

L&P					
Scenario	**Capital Costs**	**Change in Fuel Costs**	**NPPD Capacity Payment**	**Total**	**% of Current Revenue**
1	$53,446,831	$0	$12,120,000	$41,326,831	31.4%
2	$34,933,389	$3,583,635	$12,120,000	$26,397,024	20.1%
3	$18,514,261	$8,035,858	$12,120,000	$14,430,119	11.0%
4	$14,322,353	$9,350,953	$12,120,000	$11,553,306	8.8%
5	$0	$14,115,810	$12,120,000	$1,995,810	1.5%

Choosing a scenario that minimizes rate impacts for MPS customers results in the maximum rate impacts for L&P customers, and when rate impacts are minimized for L&P customers they are maximized for MPS customers.

To get an idea of what allocation would minimize the costs to both MPS and L&P, Staff plotted the total cost for the 5 scenarios. This graph is shown below.



These two lines cross at approximately 100 MW, i.e., the cost to the MPS and L&P are the same at 100 MW.

Staff's position of 100 MWs for L&P will potentially cause the rate increase to L&P customers to be almost four times the rate increase to MPS customers. However, currently the bill of a typical residential customer using the Company's estimated use of 1130 kWh per summer month and 780 kWh per winter month on MPS's residential rates is approximately 19% higher than a residential customer with the same usage on L&P's residential rate. Staff's proposed allocation will not result in GMO's rates for L&P surpassing GMO's rates for MPS. However, this proposed allocation of Iatan 2 investment and costs is not outside the probable realm of what would have occurred to the rates of L&P customers if they were still in a stand-alone St. Joseph Light & Power Company, and moves GMO's L&P rates closer to those of MPS.

<u>Conclusion</u>

Taking into account their probable resource needs if MPS and L&P each were stand alone utilities, the source of GMO's ownership rights to Iatan 2, and rate impacts, it is Staff's position that 100 MW of Iatan 2 should be allocated to L&P and 53 MW should be allocated to MPS. All additions of large base load units in Missouri initially have resulted in a large increase on the utility's revenue requirement. Staff's current research shows that the initial inclusion of St. Joseph Light & Power Company's investment and costs in Iatan 1 in its revenue requirement caused its rates to increase by over 26%. When Union Electric Company's investment and costs in the Callaway Nuclear Plant were initially included in its revenue requirement, despite having a large customer base, it caused Union Electric Company's rates to increase by 45%. Further, when KCPL's investment and costs of the Wolf Creek Nuclear plant was first included in KCPL's revenue requirement, it caused KCPL's rates in Missouri to increase by 21.75%. Despite the initial large increase in rates when these base load units were first included in the utilities' revenue requirements, in the long-term they have resulted in lower rates for the customers of these utilities - lower rates which those customers are now enjoying.

Staff Expert/Witness: Lena Mantle

13. MPS Prudent Combustion Turbines

Staff is sponsoring adjustments for MPS to continue Staff's position in GMO's last three rate cases, Case Nos. ER-2005-0436, ER-2007-0004, and ER-2009-0090 as it relates to the GMO capacity issue described above by Staff witness Mantle. The adjustments Staff is proposing reflect the continuation of Staff's position that GMO should have prudently addressed its capacity needs for MPS to replace the Aires PPA when it expired on May 31, 2005. As related by Staff witness Mantle GMO chose not to replace the Aires PPA with its least cost option of building and owning five 105 MW CTs.

Staff's position is that it was imprudent of GMO not to build and own the five 105 MW CTs in 2005. Instead, GMO only built three 105 MW CTs and continued to rely on short-term purchased power capacity contracts for the remaining 210 MWs until 2008. In 2008 GMO, through an unreported affiliate transaction with its Merchant affiliate began relying on capacity located in Mississippi from another peaking facility—four 75 MW CTs at a site called Crossroads Energy Center ("Crossroads") that was built in 2002 by Aquila Merchant. GMO's approach was short-sighted and imprudent because it placed the short-term financial considerations of GMO over the long-run financial interests of GMO's customers paying MPS rates. Due to this imprudence GMO has incurred higher long-term capacity costs than it should have and Staff is making adjustments to GMO's plant in service and expenses so those higher costs are not passed on to GMO customers. The adjustment value is the difference between including the higher costs of GMO's Crossroads in rate base less the costs of adding two additional 105 MW CTs at South Harper in 2005 when it constructed and installed three 105 MC CTs.

South Harper is a natural gas-fired peaking facility currently capable of generating up to 315 MW that is located in Cass County, Missouri. As a peaking facility, South Harper typically operates during peak electricity demand periods, such as the hot summer days in June, July, August, and September; however, it may also operate in non-peak periods to support the power system grid during maintenance on other units, or during generation shortages and emergencies, or other circumstances where it is the lowest cost plant to dispatch. Major construction of South Harper was completed in June and July 2005. The site was designed for six 105 MW CTs, but GMO has only constructed three 105 MW CTs. Staff refers to these three CTs are South Harper CTs 1, 2 and 3. Because GMO should have built five 105 MW CTs in 2005 rather than three, Staff is imputing to MPS the costs GMO would have incurred if GMO had built and installed five 105 MW CTs at South Harper in 2005. Therefore, in determining the revenue requirement for MPS Staff has, in addition to including the costs of the South Harper CTs 1, 2 and 3, included the costs of two additional 105 MW CTs--South Harper prudent CTs 4 and 5.

Because GMO is meeting its capacity needs with the CTs at Crossroads and not the South Harper prudent CTs 4 and 5 Staff has also made adjustments to its Accounting Schedules to remove all incremental costs related to the Crossroads facility that are included in GMO's test year books and records for MPS—costs such as costs to operate Crossroads, including depreciation expense, transmission charges to transfer the electricity from Mississippi to Missouri, maintenance charges including labor, operations and maintenance expenses, and property taxes. In their place, Staff has included what it believes to be a reasonable approximation of the costs that GMO would incur had it built and installed the South Harper prudent CTs 4 and 5 at South Harper in 2005.

To estimate the costs GMO would now be incurring for five 105 MW CTs at South Harper, Staff has factored up GMO's 2009 test year costs of the three CTs it built and installed at the South Harper in 2005 on a pro rata basis to be representative of five 105 MW CTs. These costs include plant and reserve, depreciation expense, maintenance charges including labor, operations and maintenance expenses, deferred taxes and natural gas pipeline reservation charges. When the plant costs for South Harper Prudent CTs 4 and 5 are included in the rate base for MPS they generate depreciation expense and an overall rate of return on the net rate base amount.

Staff calculated a pro rata amount of depreciation reserve and deferred income taxes associated with South Harper Prudent CTs 4 and 5 and made and adjustment to reflect this amount in the revenue requirement for MPS. To calculate June 30, 2010 depreciation reserve balances for South Harper Prudent CTs 4 and 5 Staff took the June 30, 2010 reserve to plant balance ratio for South Harper CTs 1, 2 and 3 and multiplied the June 30, 2010 plant balances it calculated for South Harper Prudent CTs 4 and 5 by this ratio. To calculate the level of South Harper Prudent CTs 4 and 5 accumulated deferred income taxes to include in the rate base for MPS, Staff calculated the cumulative depreciation timing differences of accelerated tax depreciation and book depreciation through June 2010 and multiplied this cumulative timing difference by GMO's approximately 38.4 percent effective tax rate.

The plant and reserve amounts for South Harper Prudent CTs 4 and 5 that Staff included in its June 2010 revenue requirement for MPS are shown below.

Acct	Prudent CTs 4 &5	**June 2010**	Dep Reserve	Net Plant
353	Transmission Plant	$2,211,353	191,282	2,020,071
340	Land	0	0	0
341	Structures	$5,142,029	386,084	4,755,945
342	Fuel Holders	$2,102,714	334,934	1,767,780
343	Prime Movers	$36,255,099	8,061,969	28,193,130
344	Generators	$9,217,285	1,727,638	7,489,647
345	Accessory Equip	$9,447,889	1,195,102	8,252,787
346	Misc Pwr Plt Equip	$66,435	8,462	57,973
		$64,442,804	11,905,471	52,537,333

The total plant costs for South Harper Prudent CTs 4 and 5 included in this case were based on Staff's estimate of the costs to build South Harper prudent CTs 4 and 5 in 2005. In Case No. ER-2005-0436, Staff used documents containing GMO's actual costs data for the purchase of the three 105 MW CTs GMO built and installed at South Harper in 2005 as the basis for Staff's calculation of the costs of South Harper Prudent CTs 4 and 5. This amount is ** __________ **, less accumulated depreciation. The chart below shows all of the plant components included in the total gross plant amount for South Harper Prudent CTs 4 and 5 included in Staff's Surrebuttal filing in Case No. ER-2005-0436:

NP

	MPS # 4	MPS # 5	Transmission	Common	Total
Plant	$18,700,000	$18,700,000	$2,100,000	$6,436,658	$45,936,658
AFUDC	$1,308,353	$1,308,353	$111,353		$2,728,059
Construction Costs	$7,600,000	$7,600,000	$0		$15,200,000
Total Plant in Service	$27,608,353	$27,608,353	$2,211,353	$6,436,658	$63,864,717

The $18.7 million estimated cost of the South Harper Prudent CTs 4 and 5 and the $2.1 million estimated cost of the transmission upgrades are addressed by Staff witness Featherstone. Added to the estimated cost of the CTs is an allowance for funds used during construction (AFUDC). AFUDC represents the cost of both debt and equity funds used to finance utility plant additions during the construction period. AFUDC is capitalized as a part of the cost of utility plant.

As the basis for its AFUDC estimate, Staff used a workpaper GMO provided that reflects the actual costs of construction of the three South Harper CTs. The cost sheet, titled "South Harper Peaking Facility Weekly Cash Flow Updated September 21st" (South Harper Construction Cost workpaper) reflects the construction costs of South Harper Units 1, 2 and 3 through September 21, 2005. The actual AFUDC costs charged to South Harper Unit #1 was $1.6 million.

This amount applied to capitalized direct charges of $23 million, results in an AFUDC rate of approximately 7%. Staff's $18.7 million cost per Ct multiplied by 7% results in the capitalized AFUDC cost of $1.3 million per CT.

Staff used the same method to determine the AFUDC rate for transmission plant. The South Harper Construction Cost workpaper for the Belton South to Peculiar transmission project shows AFUDC loadings of $187,751 based on direct charges of $3.5 million, for an AFUDC rate of 5.3%. Applying this rate to the transmission plant cost of $2.1 million, results in a capitalized AFUDC cost of $111,353.

Therefore, Staff added $7.6 million of construction costs for each CT. The CT construction costs are based on GMO's actual costs to build the three CTs at South Harper. The highest cost GMO incurred to construct any of the three South Harper CTs was $7.5 million. This was the cost of construction for South Harper CT 3.

The South Harper Construction Cost workpaper shows total costs to construct common plant at South Harper for three CTs, or 315 MW, to be $19.3 million. Staff used a ratio of 210 MW/ 315 MW and multiplied this 67% times the $19.3 million to arrive at a value of $12.9 million. Staff then applied a fifty percentage (50%) downward adjustment factor to this result. The downward adjustment was made to recognize the likelihood that building two additional CTs will increase the need for additional common plant, but the additional common plant needed by adding two CTs will be significantly less than in initial common plant built for the three CTs at South Harper.

Staff's position in Case No. ER-2005-0436, Aquila's 2005 rate case was that while the cost of constructing two additional CTs was higher in the short-term, because the rate of return is applied to a declining net plant amount over time, the cost of ownership will decline over time and it will be cheaper in the long run to own the CTs than continue to use short-term PPAs. For example, by including South Harper Prudent CTs 4 and 5 in rate base in Aquila's 2007 rate case, No. ER-2007-0004 Staff's revenue requirement recommendation increased by $12 million. This $12 million included by Staff was higher by $4.6 million than the cost for this capacity proposed by GMO in that case—$7.3 million.

Staff's position that although the cost of constructing two additional CTs was higher in the short term than relying on PPAs, because plant-related costs decline over time, it will be cheaper in the long run to build them began to bear fruit in GMO's 2009 rate case, No. ER-2009-0090. In that rate case the cost included in Staff's revenue requirement for its 310 MW of capacity (two 105 MW CTs and a 100 MW PPA) was approximately $12 million. The costs GMO included in its case for 310 MW from Crossroads was approximately $23 million, for a revenue requirement difference of about $11 million. This $11 million represents part of the cost of the imprudent capacity planning decisions of GMO that Great Plains Energy inherited when it purchased Aquila, Inc. GPE's management has deal with this cost, but it should not be allowed to pass this cost on to GMO's ratepayers. That is still Staff's recommendation to the Commission.

In this case, the cost difference between including Crossroads in rate base for MPS instead of South Harper Prudent CTs 4 and 5 is $15 million. A snapshot of this revenue requirement differential is shown below. This analysis uses the grossed up rate of return GMO proposes in this case, GMO's and Staff's respective proposed depreciation rates, and assumes no material impact of the differences in property taxes, maintenance and other related expenses between Crossroads and South Harper Prudent CTs 4 and 5.

	Crossroads	CT 3 & 4
Net Plant	$107	$52.5
Deferred Taxes	($6)	($17)
Net Rate Base	$101	$35.5
GMO-Grossed Up Rate of Return	12.5%	12.5%
Return on Rate Base	$12.6	$4.4
Depreciation	$5.5	$2.3
Transmission-Crossroads	$5.4	$0
Gas Reservation	$0.5	$2.4
Total Revenue Requirement	$24	$9
Difference		($15)

The reason for the significant difference is deferred taxes between Crossroads and Prudent CTs 4 and 5 is that GMO refuses to include the cumulative deferred taxes that have accrued on Crossroads since that plant has been operating. GMO's position is that it's Missouri regulated customers are not entitled to the deferred taxes that accrued to Crossroads while it was a Merchant Plant for Aquila. When KCPL and GMO transferred Crossroads from non-regulated Merchant Plant to Regulated Plant, Aquila recognized a significant inter-company gain which it retained for non-regulated operations and eliminated the accrued deferred taxes that should have transferred with the ownership of the Crossroads plant.

Staff Expert: Charles R. Hyneman

B. Payroll, Payroll Related Benefits including 401K Benefits Costs and

1. Payroll Costs

All employees of Great Plains Energy are considered employees of KCPL. These KCPL and GPE employees perform all services for Great Plains Energy, KCPL and GMO (MPS and L&P). An allocation of costs is necessary to assign a proper amount of payroll costs to each of the Great Plains Energy entities. Staff reviewed the allocation of actual payroll costs for each of these entities since the acquisition of the former Aquila Missouri electric operations of MPS and L&P, and allocated the annualized payroll based on this allocation.

The transfer of the former Aquila employees was made at the close of the acquisition transaction on July 14, 2008. The former Aquila entities now are providing utility services under the name KCP&L Greater Missouri Operations Company: GMO MPS, GMO L&P and GMO L&P Steam. Because all former Aquila employees providing service to the GMO MPS, GMO L&P and GMO L&P steam operations became part of the KCPL employee base, KCPL now has to allocate costs directly to each KCPL service territory and the two GMO operating entities, MPS and L&P. Additionally, L&P operations supplies utility services to electric and steam customers and L&P labor costs must be allocated between the electric and steam operations.

Based on the other allocation amounts to the GPE entities, Staff concluded that the actual charged amounts were the best allocation of payroll between KCPL, MPS and L&P. Staff utilized actual charged amounts to the three operating entities, net of joint partners, Wolf Creek, and Jeffrey Energy Center charged payroll. The joint partners' costs are amounts charged to KCPL's other partners of the generating assets owned and operated by the Company, with the exception of Wolf Creek, a separate operating company, 47% of which is owned by KCPL.

Staff annualized payroll costs in this case using actual employee levels as of the update period of June 30, 2010. Wages and salaries as of June 30, 2010, were applied to each individual employee to compute the total GPE and KCPL payroll costs on an annual basis. Annualized payroll included differential and premium pay paid to KCPL employees based on union contracts.

As of June 30, 2010, GMO's holding company, GPE, has minuscule labor costs that are to be annualized using current employee levels and current salaries. GPE provides common services such as accounting, tax consolidation, corporate legal, and governance to GPE entities. The amount of GPE payroll that relates to KCPL and the GMO entities had to be determined in order to include those costs in the total payroll.

On December 16, 2008, GPE was restructured with all GPE and GPES employees becoming KCPL employees. Because of this restructuring, the allocations factors between KCPL, GMO and GPE heavily favor KCPL, MPS and L&P, with GPE having a miniscule factor to account for the above mentioned duties.

Overtime payroll for GMO were calculated based upon a one-and-a-half year average. Staff chose this particular timeframe because the overtime hours and sum paid out indicated an upward trend, with the first 6 months of 2010 being noticeably high. These amounts are specific to KCPL, MPS and L&P service territories and, therefore, it is not necessary to include the overtime as part of the allocation process for annualized payroll. The payroll overtime costs have been directly assigned to KCPL, MPS and L&P.

As the result of KCPL's operating agreements for generating facilities with several partners, it is necessary to assign costs to these partners and remove those payroll costs from the payroll annualization that is reflected in the revenue requirement calculations. This assignment of joint partner billings is necessary to ensure that payroll costs properly billed to the joint partners are not included in the KCPL payroll costs. The level of payroll billed by KCPL to its joint owners in the Iatan and LaCygne generating stations was based upon the June 30, 2010, update period total. Staff used the Company methodology to correctly allocate the reduction in payroll costs from the billing of joint partners, and these costs were removed net of the L&P portion of Iatan before the allocation of payroll to KCPL and GMO. The other payroll costs for partners are billed to The Empire District Electric Company, the other partner in Iatan and to Westar Energy Company, the 50% partner in the two LaCygne generating facilities.

The total annualized GPE and KCPL payroll costs allocated to GMO also have to be assigned between operational and maintenance ("O&M") expense and other expense. Typically the other expense amount relates to construction and other non-expense functions of a company. The construction amounts are assigned to the work orders for construction projects. The amounts that are included in the revenue requirement calculations for GMO are the levels assigned to payroll expenses through the O&M expense ratios.

After allocating between expense and construction based on the expense factor, which in File No. ER-2010-0355 is a three-year average, the adjustment for payroll was distributed by individual FERC account based upon the actual distribution for each of those accounts for 12-months ending June 30, 2010, the update period used in this case. Adjustments L&P: E-4.3, 5.1, 14.1, 15.2, 17.1, 18.2, 24.3, 25.3, 26.3, 27.3, 28.3, 38.1, 41.1, 42.1, 46.2, 47.2, 48.2, 60.1, 61.2, 67.1, 68.1, 69.1, 74.1, 80.1, 81.1, 82.1, 89.1, 90.1, 91.1, 92.1, 93.1, 94.1, 95.1, 96.1, 97.1, 102.1, 103.1, 104.1, 105.1, 106.1, 107.1, 108.1, 109.1, 110.1, 115.1, 116.1, 117.5, 119.1, 122.1, 123.1, 124.2, 125.1, 128.1, 129.1, 131.1, 135.2, 137.1, 141.2, 142.6, 147.4, 148.1, 150.1, 152.2, 153.1, 155.1, 158.2

MPS: E-4.2, 5.1, 10.1, 11.1, 12.1, 13.1, 17.1, 18.1, 19.3, 20.3, 21.3, 30.1, 31.1, 35.1, 36.1, 39.2, 40.1, 41.2, 42.2, 46.1, 51.2, 57.2, 62.1, 63.1, 64.1, 65.1, 66.1, 76.1, 77.1, 78.1, 79.1, 80.1, 85.1, 86.1, 87.1, 88.1, 89.1, 90.1, 91.1, 92.1, 93.1, 97.1, 98.1, 99.1, 100.1, 101.1, 102.1, 103.1, 104.1, 105.1, 109.1, 110.1, 111.1, 113.1, 116.1, 117.1, 118.2, 119.1, 122.1, 123.1, 125.1, 129.1, 130.2, 131.1, 135.1, 136.4, 137.2, 139.1, 143.1, 144.1, 145.2, 146.1, 148.1, 151.1,

Staff Expert/Witness: Bret G. Prenger

2. Payroll Taxes

Staff annualized payroll taxes by applying current payroll tax rates to each employee's annual level of payroll. To compute payroll taxes for overtime, interns, premium pay, and partner billings, Staff applied an aggregate tax rate based on the annualized payroll taxes for base payroll. The payroll taxes follow the same allocation process used to allocate base payroll. Adjustments E-174.3 (L&P) and E-167.1 (MPS) to the Income Statement reflect the annualized payroll taxes based on payroll costs as of June 30, 2010.

Staff Expert/Witness: Bret G. Prenger

3. Payroll Related Benefits

Payroll related benefits general include 401k expenses, medical costs, and other employee benefits. Staff calculated annualized 401k expenses based upon the test year percentage match for GMO applied to its share of total annualized payroll. In addition, Staff removed the joint partner share of GMO 401k expenses from the annual level similar to the annualized payroll adjustment.

Staff calculated Medical costs based upon twelve months ending June 30, 2010.

Staff calculated other employee benefits, located in Account 926, based upon the twelve months ending June 30, 2010. Other benefits include items such as Educational Assistance and Recreational Activities. Adjustments E-142.7 (L&P) and E-136.6 (MPS) to the Income Statement reflect the calculated payroll related benefits based on payroll costs as of June 30, 2010.

Staff Expert/Witness: Bret G. Prenger

4. True-up of Payroll Costs

Staff will update the total payroll costs for the true-up in this case, which is based on an update period ending June 30, 2010. The same methodology used to annualize payroll as of June 30, 2010, will be used for the December 31, 2010, true-up.

Staff Expert/Witness: Bret G. Prenger

5. Iatan 2 Ownership Allocation

Staff is proposing an adjustment in Case ER-2010-0356 to include and allocate between MPS and L&P Staff's determination of GMO's ownership of Iatan 2. GMO owns 18% of both Iatan 1 and Iatan 2. Staff has included in its direct filing payroll related strictly to Iatan 1 and Iatan 2. Staff initially distributed that payroll amount equally to Iatan 1 and to Iatan 2. Then, Staff multiplied each by 18% based on GMO's ownership share. Staff assigned the resulting payroll amount for Iatan 1 to L&P. Staff allocated the resulting payroll amount for Iatan 2 to MPS and L&P based on Staff's proposal that 100MW of Iatan 2 be allocated to L&P and 53 MW be allocated to MPS. This is a reallocation of payroll that Staff had originally allocated using the payroll allocators for allocating payroll between —KCPL, MPS and L&P, 9.38% for L&P and 22.55% for MPS. However; the correct allocators for allocating Iatan 2 between L&P and MPS are: 65.40% (L&P) and 34.60% (MPS). The difference between the Iatan 2 payroll amounts Staff obtained from its original allocation and the amounts it obtained from using the correct allocators multiplied by the transfer to expense, or O&M percentage (75.39%) represents Staff's proposed adjustments. Adjustments E-4.4 for MPS and E-4.4 for L&P, respectively are Staff reallocated Iatan 2 payroll adjustments.

Staff Expert/Witness: Bret G. Prenger

6. FAS 87 and FAS 88 Pension Costs

Financial Accounting Standard (FAS) 87 states that the accrual accounting method should be used to calculate pension cost for financial reporting purposes. However, for MPS and L&P, both Staff and the Company recommend continuation of the settlement agreement originally approved in Case No. ER-2004-0034 and continued in Case Nos. ER-2005-0436, ER-2007-0004 and ER-2009-0090.

The settlement agreement provides that the minimum contributions required under the Employee Retirement Income Security Act (ERISA) will be used in determining MPS's and L&P's pension cost for ratemaking purposes. ERISA was established by federal statute in 1974 and is intended to ensure the funding of defined benefit pension plans.

FAS 87 is an accrual accounting method required by the accounting profession under Generally Accepted Accounting Procedures (GAAP) for financial reporting purposes. Under FAS 87 a company accrues (expenses) an employee's earned pension benefits over the service life of the employee. The total obligation to the employee for pension benefits is accumulated annually until retirement in the Accumulated Benefit Obligation (ABO). Both financial statement expense recognition under FAS 87 and the funding requirements under ERISA are based upon the same pension plan obligation to employees enrolled in the plan. While different assumptions are used for the timing of pension cost recognition during the service life of the employee under FAS 87 and ERISA, both FAS 87 and ERISA are intended to address *the same total* ABO by the employee's retirement date.

In GMO's last general electric rate case, Case No. ER-2009-0090, the parties entered into a settlement agreement to use the provisions that were established in GMO's previous rate cases, Case No. ER-2007-0004, which included the following provisions:

1) A Prepaid Pension Asset representing negative pension cost flowed through in rates in prior cases was agreed to in the stipulation and agreement in Case No. ER-2004-0034. This Prepaid Pension Asset is being amortized to cost of service over 5 1/2 years for the MPS division and 9.25 years for the L&P division starting with the effective date of rates established in Case No. ER-2004-0034, April 22, 2004. The unamortized balance is included in rate base for the MPS and L&P divisions. This treatment was continued in the stipulation and agreement in Case No. ER-2005-0436 and ER-2007-0004 and ER-2009-0090.

2) Annual pension cost reflected in cost of service is to be based upon MPS and L&P's ERISA minimum contributions requirements.

3) A tracking mechanism tracks the difference between the pension cost included in rates and MPS and L&P's actual pension fund contributions during the period that existing rates are in effect. The resulting regulatory asset (actual fund contributions exceed rate recovery) and/or regulatory liability (actual fund contributions are less than rate recovery) are included in rate base and amortized to cost of service over 5 years.

The rate base amounts and cost of service adjustments Staff has reflected in this current case, Case No. ER-2010-0356, are based on continuation of the agreements reached in the above-referenced stipulation and agreements.

Staff's rate base calculation includes a Missouri jurisdictional balance of $0 and $10,253,303 for MPS and L&P prepaid pension asset unrecovered balance, as of June 30, 2010, respectively. MPS's prepaid pension asset was fully recovered on October 31, 2009; therefore, MPS's balance was set to $0. The L&P unrecovered balance will be updated through December 31, 2010, in the true-up portion of this case.

As of June 30, 2010, MPS and L&P have respectively collected $696,938 and $2,022,355, less in rates than the actual contributions made to the pension fund. This regulatory asset is reflected as an increase to MPS's and L&P's rate base and amortized as an increase to pension cost over 5 years. Adjustments E-136.1 and E-142.1, in Staff Accounting Schedule 10, respectively adjust the 2010 test year pension cost for MPS and L&P to reflect a normalized level of contributions to the pension fund. A full year of amortization is included in the cost of service for the L&P prepaid pension asset, therefore there is no adjustment necessary for this case.

Additionally, KCPL and GMO made a determination to combine all of its pensions and OPEBs into one plan under its parent company, Great Plains Energy. The Company and its actuary, Towers Watson, proposes to switch the accounting method for calculating pension costs in this rate case from minimum ERISA (contributions) to FAS 87 (accrual). The reasoning for this change is that many of their employees now perform services for both KCPL and GMO during any given year. This means it is impossible to isolate specific pension benefits earned while performing services for KCPL. For example, if an employee splits time between KCPL and another entity based on a ratio of 75%/25% one year and 40%/60% the next, there is no way to track the separate benefits being earned and the underlying asset values supporting these benefits for KCPL or GMO on a prospective basis. As a result, the existing regulatory assets (from minimum ERISA) should be amortized until the balances reach $0. In addition, the Company proposes a different pension tracking mechanism be implemented subsequent to the effective date of new rates in this proceeding, based on pension accrual accounting (FAS 87).

As a result of the Company combining its pension plans under the FAS 87 accounting method for this case, Staff reflected the Company's pension costs under FAS 87 in Staff's income statement in this case consistent with the ratemaking treatment applied to other regulated utilities within Missouri. The rate base amounts and cost of service adjustments Staff has reflected in this current case, Case No. ER-2010-0356, are based on continuation of the agreements reached in the stipulation and agreements in previous rate cases based upon ERISA. However, a different pension tracking mechanism will need to be implemented subsequent to the effective date of new rates in this proceeding, based on pension accrual accounting. MPS & L&P's ongoing level of FAS 87 cost recognized in rates in this case is $7,945,506 and $672,833, respectively.

Staff Expert/Witness: Paul R. Harrison

<u>7. FAS 106 – Other Post Employment Benefit Costs (OPEBs)</u>

Other Post-Employment Benefit Costs (OPEBs) are those costs incurred by the Company to provide certain benefits to retirees. These benefits include medical, dental, vision, and life insurance benefits. The Company must determine its OPEBs expenses based on Financial Accounting Standard No. 106, *Employers' Accounting for Postretirement Benefits Other than Pensions* (FAS 106) and Staff has provided sufficient costs in its revenue requirement calculation to reflect a proper level for these OPEB costs for MPS and L&P. Section 386.315, RSMo. (2000) requires that the Commission:

> ...not disallow or refuse to recognize the actual level of expenses the utility is required by Financial Accounting Standard 106 to record for post retirement employee benefits for all the utility's employees, including retirees, if the assumptions and estimates used by a public utility in determining the Financial Accounting Standard 106 expenses have been reviewed and approved by the commission, and such review and approved shall be based on sound actuarial principles.

Section 386.315.2 essentially requires a utility to use an independent external funding mechanism that limits restricts disbursements only for "qualified retiree benefits" for the FAS 106 costs recognized in a utility's financial statements. Section 386.315 also mandates that all of the funds be used for employee or retiree benefits.

MPS and L&P are funding their annual FAS 106 costs. Staff adjustments E-136.3 and E-142.3 adjust the MPS and L&P test year 2009 FAS 106 OPEBs costs to reflect the more current FAS 106 calculation as of June 30, 2010.

Staff's adjustment annualizes OPEBs expense as calculated under FAS 106, for MPS and L&P employees. The amount of OPEB expense included in Staff's cost of service calculation reflects MPS' and L&P's current liability to provide retiree medical payments to its current employees as well as to its retired employees.

Staff Expert/Witness: Paul R. Harrison

<u>8. OPEB Tracker</u>

Based upon an analysis of the three previous years of the MPS and L&P's OPEB expense Staff determined that the OPEB expense fluctuated significantly from year to year. By using a tracker, the cost of the OPEB expense will be recovered through rates for both the rate payer and

Company in future rate cases. At the present time Empire District Electric Company, Empire District Gas Company and AmerenUE all have an OPEB tracker.

MPS and L&P has requested a tracker mechanism for OPEB expense in this case, whereby any excess or deficiency of the Company's OPEB rate allowance, compared to its ongoing level of OPEB expense as determined by its actuary, would be treated as a regulatory asset or liability which would be included in MPS and L&P's rate base and amortized, as an addition or reduction to OPEB expense, over a five-year period.

A regulatory asset or liability would be established on the Company's books to track the difference between the level of OPEB expense during the rate period and the level of OPEB expense built into rates for that period, similar to the pension tracking mechanism. If the OPEB expense during the period is more than the expense built into rates for the period, the Company would establish a regulatory asset. If the OPEB expense during the period is less than the expense built into rates for the period, the Company would decrease any existing regulatory asset or establish a regulatory liability. If the OPEB expense becomes negative, a regulatory liability equal to the difference between the level of OPEB expense built into rates for that period and $0 would be established. Since this is a cash item, the regulatory asset or liability would be included in rate base and amortized over 5 years in the next rate case.

Staff Expert/Witness: Paul R. Harrison

9. Supplemental Executive Retirement Plan (SERP) Expense

Included in Staff's revenue requirement recommendation for GMO is the test-year amount of recurring (non lump-sum) SERP payments made by the Company to its former executive and other highly-compensated employees as appropriately adjusted and allocated by Staff.

A SERP is an additional executive pension compensation program that provides benefits to highly-compensated employees over and above the benefits provided under the "all-employee" regular pension plan. A SERP exists only because the Internal Revenue Code ("IRC") does not permit a tax deduction for pension expense above a certain dollar amount. Companies create a SERP to allow its highly-compensated employees to receive pension benefits over and above the amount that the IRC allows as a reasonable business deduction.

Staff adjusted MPS' test year per book amount of SERP expense and included MPS-GMO's 2009 income statement to a level Staff considers appropriate. Staff's proposed level of SERP expense for MPS-GMO is $89,321 which is lower than MPS-GMO's test year per book amount of $95,246 net SERP expense.

MPS capitalizes a portion of its SERP expense to capital projects, such as regulatory assets and construction work-in-progress. Staff does not believe that SERP payments should be capitalized in a manner similar to normal pension expense. The SERP payments are made to former employees who provide no current or future value to the utility's operations or the construction of capital assets. Therefore, all of the payments, to the extent that they are reasonable and prudently incurred, should be charged to expense.

Staff's SERP adjustment for MPS is based on the actual recurring payments made as shown in GMO's response to Staff Data Request No. 301. In that data request response, GMO listed for MPS each former executive who received a SERP payment in 2009 and the amount of the SERP payment made. However, it does not appear that GMO made an allocation of the SERP payments to MPS that was representative of the allocation of expense these former Aquila, Inc. corporate employees charged to Missouri regulated operations (MPS and L&P). For example, in prior rate cases Aquila Inc. allocated only approximately 20 percent of the payroll and other costs of the Chief Administrative Officer to MPS and approximately 8 percent to L&P, for a total amount of 28 percent to Missouri regulated operations. In its adjustment in this rate case, GMO appears to be allocating 100 percent of the SERP payments to Missouri regulated operations. In its adjustment, Staff attempted to allocate the appropriate amount of SERP expense for each former Aquila executive based on service provided these employees provided to Missouri regulated operations.

Staff also made an adjustment to the amount of annual recurring SERP payments made to two former Aquila executives from in excess of $70,000 per year to approximately $50,000 per year. SERP in the amount of $50,000 is the amount paid to a former Aquila Senior Vice-President with over 22 years of service to Aquila, and is the amount Staff established as a ceiling of reasonableness. Staff believes any recurring SERP payment to former Aquila executives above this amount is excessive and should not be included in cost of service.

Finally, in Aquila's past rate cases, Staff took issue with the fact that a significant level of Aquila's SERP expense was based on compensation received as bonus payments and incentive compensation that was not included in cost of service. To prevent SERP expense based on non-regulated compensation from being included in its adjustment, Staff reduced each former employee's SERP payment by 20 percent prior to allocation to Missouri regulated operations. The 20 percent is an estimate of the amount of annual recurring SERP expense that is based on non-regulated compensation.

Staff did not allocate any of the SERP expense for the former Aquila executives to L&P. On October 19, 1999, Aquila Inc. (then named UtiliCorp United Inc.) and St. Joseph Light & Power Company (SJLP) filed a Joint Application seeking authority to merge SJLP with Aquila. The Commission issued a Report and Order on December 14, 2000, approving the merger. Since all or nearly all of the former Aquila executives provided most of their service to Aquila prior to the merger, Staff determined it would not be appropriate to charge L&P customers an expense that was not related to any economic benefit provided to them.

Staff has made an adjustment to remove the test year per book amount of SERP for L&P and therefore has not included in GMO's revenue requirement any SERP payments made to the former SJLP executives. When Aquila merged with SJLP in 2000, it also purchased the assets in SJLP's funded SERP. It has been Staff's position in prior rate cases, which it continues in this case, that the assets in this SERP fund are sufficient to pay for a reasonable level of SERP expense over the lifetime of the former St. Joseph Light and Power (SJLP) executives. Therefore, since Aquila, Inc. purchased the assets in the SERP fund when it merged with SJLP, there was no longer any future SERP expense to be recognized for the former SJLP executives. It is and has been Staff's position that all SERP payments to the former SJLP executives should be made from the SERP fund that was acquired by Aquila, Inc. and subsequently acquired by Great Plains Energy in its acquisition of GMO in 2008.

Because of SERP's unique nature and the fact that the benefit represents an additional executive pension benefit over and above what is already provided in the regular pension plan, Staff treats SERP costs somewhat differently from normal employee pension costs. Staff's policy has been and continues to be the recommendation that SERP costs be included in the Company's cost of service if such costs are not excessive, are reasonably provided for, and are able to be quantified under the known and measurable standard. Staff's proposed level $89,321 for MPS's annual recurring SERP payments meets this test.

Staff Expert/Witness: Charles R. Hyneman

10. Short-Term Incentive Compensation

KCPL has three separate, short-term annual incentive compensation programs for executive, management, and union employees. These programs are designed to grant cash awards of various amounts calculated based upon designated annual metrics. Amounts accrued under the terms of each program during the year are paid out during the first quarter of the following calendar year. The three incentive compensation programs are: 1) The Rewards program, reserved for bargaining (union) employees; 2) The Value-link program, reserved for management-level KCPL employees; and 3) The Annual Executive Incentive Plan, reserved for senior KCPL management employees.

In prior plan years KCPL's program was designed with a "trigger", an Earnings Per Share ("EPS") threshold that was required to be met before any employee received any funds under the plans. However, if the "trigger" was not met, the plan terms dictated that no payouts were to be made, regardless of any achievement of goals, financial or otherwise. This mechanism has been removed for all plans beginning with the 2009 plan year and this removal consequently reduces the volatility of payouts from year to year.

The incentive plans all have benchmarks that identify targets that KCPL employees are expected to achieve before any cash payouts are awarded. These targets are established each year of the incentive plan and communicated to the employees early enough so that the employees have sufficient opportunity to reasonably achieve the benchmarks.

The Rewards program covers bargaining unit employees from IBEW Local 1464 (approximately 691 employees), IBEW Local 412 (approximately 834 employees), and IBEW Local 1613 Unions (approximately 417 part/full time employees). ** ____________________

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The Value-link program covers non-executive management-level KCPL employees, such as Plant Manager or Insurance Manager. **

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The third short term annual incentive plan is the Annual Executive Incentive Plan ("the Executive Plan"), designed for the top 22 officers of the Company. ** ____ **

** ____ ** Remaining in the cost of service are the projected payouts at the target level for salaries as of June 30, 2010 as updated by the Company. Staff has proposed to remove the amounts the Company did not include in the cost of service in its direct filing in prior rate cases. In those cases, the Commission adopted Staff's position. Staff would

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have proposed a similar adjustment to incentive compensation if the full amount were included in the cost of service.

While Staff agrees with the adjustments GMO has made in this case, Staff continues to evaluate the Company's philosophy on compensation and benefits. Incentive compensation is but one factor in KCPL's total pay and benefits package, in addition to deferred compensation, pension, and health and welfare benefits.

MPS: E-4.3, 12.2, 36.2, 62.2, 85.2, 93.2, 110.3, 117.6, 129.4

L&P: E-4.3, 66.3, 89.3, 97.3, 115.3, 123.5, 135.4

Staff Expert/Witness: Bret G. Prenger

11. Long-Term Incentive Compensation

The Long Term Incentive Compensation Plan ("the plan") for the 2009-2011 calendar years was based on two goals, each weighted at 50%. The two goals were FFO to Total Adjusted Debt and Earnings Per Share ("EPS"). The purpose of the plan is to encourage executive and other key KCPL employees to acquire a vested interest in the growth of and performance of Great Plains Energy. Eligible employees include executives and other employees of GPE and KCPL, as approved by the Compensation and Development Committee of the Board of Directors. The awards generally given are 50% restricted stock, with the number of shares determined at the date of grant based upon the GPE stock price. The other 50% of the awards will be performance shares with that number granted to be determined by the fair market value at date of grant. Time-based restricted awards and performance shares will be payable in GPE common stock. As part of GMO Adjustment CS-11, the Company removed all costs associated with long-term officer incentives stating "the costs are ordinary and reasonable business expenses; however, we do not believe such costs should be borne by ratepayers." Staff

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agrees with the adjustment and has removed all associated costs from Staff's revenue requirement calculation.

Adjustments: L&P: E-135.3 MPS: E-129.3

Staff Expert/Witness: Bret G. Prenger

C. Maintenance Normalization Adjustments

Maintenance expense is the cost of maintenance chargeable to the various operating expenses and clearing accounts. It includes labor, materials, overheads, and any other expenses incurred in maintaining the Company's assets - including power plants, transmission and distribution network of the electric system, and the general plant. Specific types of maintenance work tied to specific classes of plant are listed in functional maintenance expense accounts in the FERC Uniform System of Accounts ("USOA") for the various types of utilities. Maintenance expense normally consists of the costs of the following activities:

- Direct field supervision of maintenance;
- Inspecting, testing and reporting on condition of plant, specifically to determine the need for repairs and replacements;
- Work performed with the intent to prevent failure, restore serviceability or maintain the expected life of the plant;
- Testing for, locating, and clearing trouble;
- Installing, maintaining, and removing temporary facilities to prevent interruptions; and
- Replacing or adding minor items of plant, which do not constitute a retirement unit.

Staff analyzed maintenance costs from 2001 through 2009, by functional area for production, transmission, distribution, and general plant by FERC account. Staff separated maintenance between labor and non-labor costs. Since labor costs are specifically addressed as a component in the cost of service analysis, labor costs were segregated from the non-labor costs to perform the review of maintenance costs. Staff's detailed position related to payroll is located under the heading *Payroll, Payroll Related Benefits* in this report. The maintenance analysis was done only on non-wage maintenance and operating costs.

Several steps were taken to analyze the maintenance data. They included examining the non-labor maintenance amounts to identify any characteristics of the maintenance dollars such as trends or fluctuations from one period to another. Another approach used by Staff, was to compare functional averages which included using a two (2) year average through a seven (7) year average to determine if there were fluctuations with each functional area. Each of the costs by year and averages for maintenance were also compared to the 2009 Test Year. Staff reviewed the data as detailed above to establish a maintenance level that will result in an annual level of the Company's future maintenance costs. Staff's results are presented in the following table;

Results of Staff's Non-Labor Maintenance Analysis		
	GMO-MPS	**GMO-L&P**
Steam Production Maintenance	3-Year Average (2007-2009)	3-Year Average (2007-2009)
Other Production Maintenance	3-Year Average (2007-2009)	3-Year Average (2007-2009)
Transmission Maintenance	3-Year Average (2007-2009)	3-Year Average (2007-2009)
Distribution Maintenance	3-Year Average (2007-2009)	2009 Test Year

The adjustments for MPS shown on Staff Accounting Schedule 10 are: Production Maintenance E-17.2, E-18.2, E-19.2, E-20.2, E-21.2, E-39.1, E-40.1, E-41.1 and E-42.1. Transmission Maintenance E-72.1, E-76.2, E-77.2, E-78.2, E-79.2 and E-80.1. Distribution Maintenance E-97.2, E-98.2, E-99.2, E-100.2, E-101.2, E-102.2, E-103.2, E-104.2 and E-105.3. The adjustments for L&P shown on Staff Accounting Schedule 10 are: Production Maintenance

E-24.2, E-25.2, E-26.2, E-27.2, E-28.2, E-45.1, E-46.1, E-47.1 and E-48.1. Transmission Maintenance E-78.1, E-79.2, E-80.2, E-81.2, E-82.2, and E-83.1

Staff Expert/Witness: Karen Lyons

1. Iatan 2 O&M Expenses

Iatan 2 met its in–service criteria on August 26, 2010. Iatan 2 has been included in the Estimated True-up Case through the December 31, 2010. Staff will include GMO's estimated amounts for GMO's share of Iatan 2 O&M expenses in its true-up filing, for the true-up period ending December 31, 2010.

Staff recommends the Commission authorize a tracker for Iatan 2 O&M expense, so the actual cost of the O&M expense related to Iatan 2 will be recovered through rates for both the rate payer and Company in future rate cases. Given KCPL's very limited operation experience with Iatan 2 at this time, a tracker protects both GMO and its customers from including projected costs in rates that will in all likelihood vary from the actual costs associated with Iatan 2's O&M expense.

Staff Expert/Witness: Karen Lyons

D. Depreciation - Clearing

During the test year, the Company included depreciation for transportation equipment that was charged to expense through a clearing account. Staff made an adjustment to remove the depreciation amount booked to the clearing account. MPS Adjustment E-148.2, L&P Adjustment E-155.2.

Staff Expert/Witness: Karen Lyons

E. SJLP Merger Transition Costs

On October 19, 1999, Aquila, Inc. (then named UtiliCorp United Inc.) and St. Joseph Light & Power Company (SJLP) filed a Joint Application seeking authority to merge SJLP with Aquila. The Commission issued a Report and Order on December 14, 2000 with which it authorized the merger.

GMO's current electric rates for MPS and L&P reflect the continuation of a 10-year recovery of transition costs Aquila incurred during the process of integrating SJLP's electric operations into Aquila's Missouri regulated electric operations. The Commission approved recovery of transition costs associated with the merger of the electric operations of SJLP and Aquila to be recovered over ten years when it approved the *Nonunanimous Stipulation and Agreement*, in Case No. ER-2005-0436, in particular paragraph 12 of that agreement. In the associated *Staff's Suggestions in Support of the Nonunanimous Stipulation and Agreement*, at paragraph 18, Staff informed the Commission that Staff and Aquila agreed to an annual amortization of $314,886 for MPS and $106,187 for L&P. The Commission approved this agreement in its *Order Approving Stipulation* issued on February 23, 2006.

Because GMO records this amortization below-the line for accounting purposes, an adjustment is necessary to bring the cost above the line for ratemaking purposes. Staff made adjustments to the MPS and L&P income statements to reflect a *pro rata* 10-year amortization of these transition costs.

Staff Expert: Charles R. Hyneman

1. Leases

Lease costs are those costs incurred by the Company in leasing its corporate headquarters. Staff examined these costs for test year 2009 and updated them through

June 30, 2010. KCPL moved its corporate headquarters to One Kansas City Place, 1200 Main Street, Kansas City, Missouri during the fourth quarter of 2009.

Staff recognized the monthly base rent for the headquarters and multiplied that by 12 months to reflect an annualized rent amount. In addition to the lease rent amount, the Company has to pay other costs for customer and employee parking, as well as the annual cost for the building's electricity. KCPL currently rents four classifications of parking spaces: Visitor, Reserved, High Profile Vehicles, and Unreserved. To calculate an annualized amount for parking, Staff took the number of spaces provided in each category times the monthly rate, then applied that total times 12 months. Also, Staff picked up the adjustments of the Company to back out amounts that were associated with other standard parking accounts, so as to avoid double-counting this expense. KCPL pays electricity at a rate per square foot leased for the building. Once the three portions of the lease expenses are totaled (base rent, parking, and electricity) those amounts are then allocated out between KCPL, GMO, and GPE.

When the Company relocated to the new location, it was allowed 270 days (9 months) of rent free time, called an abatement period. Staff calculated an adjustment to reflect the "free rent" over a 5 year timeframe, and adjusted it out of the test year lease expense. Staff handled the calculation of this adjustment in a manner similar to the corporate headquarters lease adjustment. Staff took the base rent and parking expenses and instead of annualizing them for a full 12 months, did the multiplication times a 9 month period.

Staff adjusted the Company's test year amount for lease rent during the substantial period of time KCPL was paying the final months of its lease at its previous headquarters and paying leasing payments on its new corporate headquarters while it was being renovated. The leasehold adjustment results in a decrease in Total Company lease expense that is identified as Adjustment

E-154.1 (L&P) and E-141.1 (MPS). An additional adjustment is being made to reflect the decrease for the abatement period—this is identified as Adjustment E-154.2 (L&P) and E-141.3.

Adjustments E-154.1, E-154.2, E-158.1, 136.1 (L&P)

Adjustments: E-141.1, E-141.3, E-130.1, and 151.2 (MPS)

Staff Expert/Witness: Bret G. Prenger

2. Property Tax Expense

Each year KCP&L-Greater Missouri Operations (GMO or Company) is billed by each of the taxing authorities that have jurisdiction over the Company's property. Tax bills for the year are based (assessed) on the property GMO owns exclusively on January 1st of that calendar year. The property taxes assessed on January 1st of each year are not due to the taxing authorities until December 31st of that same year. The test year used in this case is the 12-month period ending December 31, 2009, updated through June 30, 2010. Since the update period in this case is June 30, 2010, Staff determined the annualized property taxes based on the property GMO had in-service on January 1, 2010. Staff applied a property tax ratio based on actual 2009 property tax payments to January 1, 2009 plant. This ratio of property taxes when applied to the January 1, 2010 plant provides the amount of property taxes expected to be paid for 2010. Since the actual 2010 property taxes owed by the Company have not been paid as of the update period, June 30, 2010, Staff plans on updating GMO's property taxes for the true-up which will be through December 31, 2010. Because the update in this case is June 30, 2010 property tax expenses for 2010 were annualized as of the January 1, 2010 date. This calculation is an estimate of the total 2010 property tax expense. Both Staff and the Company typically accomplished this by looking to the tax rate paid for the previous year, and then applying it to the property owned at the start of the current year. For the current rate case, Staff obtained from

GMO the total amount of taxable property owned on January 1, 2010, and then applied to it the tax rate assessed to the Company in 2009. The property tax rate assessed in 2009 is calculated by dividing the total amount of property tax paid by the Company by the total cost of the taxable property owned on January 1, 2009. Any required payments in lieu of taxes ("PILOTs") applicable to non-taxable property were added to the total estimated tax for 2010. Staff believes that the property tax expense arrived in this manner is the best available information, since it relies on the actual January 1, 2010 balance of GMO's property, and uses the most recent, known tax rate (2009), without attempting to estimate any change in the rate of taxation for 2010 that is not known as of the update period June 30, 2010. The property taxes will be trued-up during that phase of the case. During the true-up Staff will examined the actual amount paid for property taxes for 2010 as that amount will be known at the end of the year.

Staff adjusted test year property tax expense in order to include in rates the annualized level of 2010 property taxes. Staff's approach is consistent with that taken previously and received several favorable rulings from the Commission in prior cases, most recently in KCPL's 2006 rate case. In its Report and Order issued in Case No. ER-2006-0314 the Commission stated the following:

> Staff recommends that the Commission calculate property tax expense by multiplying the January 1, 2006 plant-in-service balance by the ratio of the January 1, 2005 plant-in-service balance to the amount of property taxes paid in 2005. KCPL wants the property tax cost of service updated to include 2006 assessments and levies. The Commission finds that the competent and substantial evidence supports Staff's position, and finds this issue in favor of Staff.

Based on the methodology addressed earlier, Staff made an adjustment to include an annualized amount for property taxes. Adjustment for MPS E-170.1 and L&P E-175.1 reflects the annualized levels.

Staff Expert/Witness: Karen Lyons

3. Bad Debt Expense

Bad debt expense is the portion of retail revenues MPS and L&P are unable to collect from retail customers by reason of bill non-payment. After a certain amount of time has passed, delinquent customer accounts are written off and turned over to a third party collection agency for recovery. If MPS and L&P are subsequently able to successfully collect some portion of previously written off delinquent amounts owed, then those amounts collected reduce the actual write-offs. This results in the net write-off which is used to determine the annualized level of bad debt expense.

Staff calculated the annualized bad debt expense by examining the billed revenues for the twelve months period ending December 31, 2009, and actual 12-month history of billed revenues that were never collected (actual net write-offs) for the twelve months ending June 30, 2010. From this information a bad debt ratio was derived, which was then applied to Staff's annualized level of retail revenues to obtain the annualized level of bad debt expense. The apparent lag time between the net retail sales and actual net write-offs in Staff's calculation is consistent with MPS's and L&P's position on how bad debt write-offs are accounted.

The Company asserts that it takes approximately six months for a customer's unpaid bill to be written off after the customer receives service. Staff's adjustment for bad debt expense adjusts the test year results to reflect a level of bad debt expense that is consistent with Staff's annualized level of retail revenue. These are adjustments E-112.1 for MPS and E-118.1 for L&P.

Staff Expert/Witness: Amanda C McMellen

4. Advertising Expense

In forming its recommendation of the allowable level of advertising expense, Staff relied on the principles the Commission followed as a result of the 1986 Kansas City Power & Light rate case, (Case No. EO-2005-0329 beginning with the 2006 rate case, Case No. ER-2006-0314). In Re: Kansas City Power and Light Company, 28 MO P.S.C. (N.S.) 228 (1986) ("KCPL"), the Commission adopted an approach that classifies advertisements into five categories and provides separate rate treatment for each category. The five categories of advertisements recognized by the Commission are:

1. General: advertising that is useful in the provision of adequate service;
2. Safety: advertising which conveys the ways to safely use electricity and to avoid accidents;
3. Promotional: advertising used to encourage or promote the use of electricity;
4. Institutional: advertising used to improve the company's public image;
5. Political: advertising associated with political issues.

The Commission adopted these categories of advertisements because it believed that a utility's revenue requirement should: "1) always include the reasonable and necessary cost of general and safety advertisements; 2) never include the cost of institutional or political advertisements; and 3) include the cost of promotional advertisements only to the extent that the utility can provide cost-justification for the advertisement." (Report and Order in KCPL Case No. EO-85-185, 28 Mo.P.S.C. (N.S.) 228, 269-271 (April 23, 1986)).

In response to data requests, GMO provided a list of all costs associated with advertising and a brief description of those costs. Staff held multiple meetings and phone discussions with the Company to review these costs and ask questions regarding the Company's implementation of its new "Connections" program. The Connections program was created by the Company to help lower income customers with assistance on timely payment methods. The program also makes available efficient household appliances for customers. The purpose of Staff's review of GMO's advertising costs was to ensure that only advertising costs for programs necessary for the provision of safe and adequate utility service are included in the Company cost of service. For example, all costs for safety advertising and indirectly related to safety advertising were included as well as other costs necessary for GMO to communicate with its customers on utility matters. Staff removed test year expenses incurred by the Company for advertising programs that are appropriately classified as institutional image in nature.

Following the Company/Staff meetings, Staff has come to the conclusion to make adjustments to Accounts 908.000 and 909.000, as well as to pick up the Company adjustments to Accounts 913.000 and 930.100. The 908 Account represents the Connections program, and while certain aspects of the program are beneficial, Staff believes a significant portion of the program represents costs pertaining to CEP/Energy Efficiency and DSM, which in prior cases are costs Staff and Company have agreed to capitalize. Staff chose to expense 50% of the costs and then capitalize the other 50% of the costs dealing with this program. This is referring to charging the costs to a plant account as compared to charging them strictly to expenses. Account 909 deals with general advertising costs in which after review, Staff found several costs also associated with CEP and Energy Efficiency. Based on the handling of these costs in case ER 2009-0089, Staff believes they should also be capitalized. Finally, Staff chose to include the two Company adjustments for accounts 913 and 930.1 that simply reflect the change between test year and known and measureable.

Adjustments L&P E-123.2, E-124.1, E-130.1, E-152.1

Adjustments MPS: E-117.2, E-118.1, E124.1, 145.1

Staff Expert/Witness: Bret G. Prenger

5. Dues and Donations

Staff reviewed the list of membership dues paid and donations made to various organizations, that GMO charged to its' utility accounts during the test year. Consistent with Staff policy for many years, Staff included all dues payments made by GMO to each area's Chamber of Commerce, and removed the other dues, as Staff believes that these additional amounts are not necessary in the provision of utility service. This adjustment was made to Account 930.2. In addition, Staff removed costs Staff considers to be personal or of no benefit to the ratepayer and thus not appropriate for inclusion in a utility's cost of service. Staff also removed costs associated with Dollar-Aide contributions, including an adjustment that the Company chose to apply to their case.

Adjustments L&P: E-117.1 and E-153.2

Adjustments MPS: E-111.3 and E-146.2

Staff Expert/Witness: Bret G. Prenger

6. Debit/Credit Card Acceptance Program

In September 2009, MPS and L&P implemented a Credit/Debit Card payment program designed to offer utility ratepayers a simplified, quick, convenient way to pay their bills, and to manage their accounts electronically. The program is offered by MPS and L&P in an agreement with Western Union through its SpeedPay service, which acts as a third party facilitator for the processing of payments to MPS and L&P. When payment is made by a customer through the credit or debit card system, MPS and L&P will receive payment from Western Union. Payment options available to customers through the program include the Interactive Voice Response System ("IVR") and or by registering on MPS's and L&P's website. Payment through the website offers two options one time payments or what the Company terms the, "recurring card payment option," which is available through registration on its website. The cost for providing this service is absorbed by MPS and L&P and later built into rates; therefore, customers who use this payment option are not charged any direct transaction fees. Since the introduction of the program in September 2009, customer participation has been gradually increasing. Participation is projected to increase into the future as more customers become aware of the program. As customer participation increases, the per unit transaction cost to MPS and L&P for providing the debit/credit payment service will decline.

Staff has included in its cost of service an annualized amount associated with the credit and debit card program based upon the total card level and per unit transaction cost as of the six months ending June 30, 2010 multiplied by two, which represents an ongoing level of costs. The cost was then allocated to MPS and L&P based on customer levels at June 30, 2010. These adjustments are represented in Staff's Accounting Schedules as E-111.4 for MPS and E-117.3 for L&P.

Staff Expert/Witness: Amanda C McMellen

7. Accounts Receivables Bank Fees

The selling of accounts receivable results in the Company collecting revenues on an accelerated basis from the lending institution. The adjustment for bank fees relate to the costs of this program. The benefit to the company is that it receives enhancement to its cash management. For rate making purposes this enhancement is reflected in the acceleration of the collection process, identified through a shorter revenue lag in the CWC schedule, than otherwise would have occurred absent the sale of the accounts receivables. As mentioned earlier, GMO was unable to continue an accounts receivable sale program due to poor financial decisions. Prior to its financial downturn, the Company had established a program with Ciesco, an affiliate of Citibank. The program involved a loan from a third party backed by MPS and L&P accounts receivables. When the Company began to experience a severe decline in its credit rating, Ciesco terminated the program. The termination of the accounts receivable program was the direct result of the Company's poor financial condition and has caused a detriment to MPS and L&P ratepayers. The loss of the sale of the accounts receivables resulted directly from the problems that Aquila faced in its non-regulated ventures.

In 2009, GMO began negotiations with account securitization facilities to establish an account receivable contract. GMO was unable to establish an accounts receivable contract because it did not have at least three years of account receivable data as a standalone company. GMO provided the following explanation as to why it was unable to establish an account receivable program.

> "KCP&L GMO ("GMO") pursued the establishment of a $55 million accounts receivable securitization facility in 2009 through the Bank of Tokyo-Mitsubishi-UFJ ("BTM"). However, BTM notified GMO in July 2009 that its credit committee would not approve funding such a facility because there was not at least three years of standalone GMO accounts receivable data available post-acquisition by Great Plains Energy. Following BTM's rejection of the transaction, GMO approached JP Morgan to gauge their interest in such a facility and received the same feedback."

Based on the Company's past financial problems and the KCPL acquisition, Staff determined an adjustment should be made for the bank fees had the program been in place. KCPL currently sells approximately 72% of its account receivables, which include the account receivables of GMO and L&P. When calculating an appropriate amount for GMO and L&P, Staff used the receivable balance from December 31, 2009. Adjustment E-116.2 (L&P) and E-110.3 (MPS).

Staff Expert/Witness: Bret G. Prenger

8. Outsourced Meter Reading

GMO contracts with a third party to perform meter reading services for MPS. The third party service provider is Corix Utilities (Corix). Corix bills the company based on the number of meter reads it performs each month. Staff made an adjustment to the 2009 test year to reflect an annualized amount. Adjustment E-109.2

Staff Expert/Witness: Karen Lyons

9. Miscellaneous Test Year Adjustments

In its direct filing, GMO proposed Adjustment CS-11 which includes several miscellaneous adjustments. Among the miscellaneous adjustments were the test-year executive expense reports, and other items that are non-recurring or that should be booked below the line. Additionally, KCPL identified the effects of an error in the Massachusetts formula. The Massachusetts formula is used to allocate expenses between operating units and the holding company, namely KCPL, GMO, and GPE, respectively. Staff has included the effects of KCPL's change in the Massachusetts formula with the exclusion of labor. Staff's payroll adjustment sufficiently captures the correct allocation of costs between KCPL, GMO, and GPE. Adjustment Numbers E-12.3, E-14.1, E-57.4, E-62.3, E-87.2, E-93.3, E-98.3, E-109.4, E-116.2, E-129.5, E-130.4, E-132.1, E-133.1, E-140.5, E-141.1, E-151.3, E-157.1, E-165.1, and E-174.1 to the MPS Income Statement and Adjustment Numbers E-61.2, E-66.2, E-91.2, E-97.2, E-103.2, E-115.4, E-122.2, E-135.5, E-136.3, E-138.1, E-139.1, E-142.8, E-147.5, E-148.2, E-153.4, E-158.3, E-166.1, E-172.1, and E-180.1 to the L&P Income Statement account for the above miscellaneous expenses in the cost of service.

Staff Expert/Witness: Keith A. Majors

10. Iatan Unit 1 Turbine Trip Additional AFUDC removed in Staff's Construction Audit and Prudence Review

In Staff's "Construction Audit and Prudence Review" of the Iatan Construction Project dated November 3, 2010, Staff captured the additional Allowance for Funds used During Construction ("AFUDC") due to the Iatan Unit 1 turbine start-up failure GMO owns an 18% share of Iatan 1.

For regulated utility companies the AFUDC is the non-cash cost of financing particular construction projects. During construction and prior to the plant providing utility service, this finance cost is capitalized to the construction work order in the same manner as other construction costs such as labor and materials. The Federal Energy Regulatory Commission (FERC) Uniform System of Accounts (USOA) identifies under Electric Plant Instructions, paragraph 17, that AFUDC:

> Includes the net cost for the period of construction of borrowed funds used for construction purposes and a reasonable rate on other funds when so used, not to exceed, without prior approval of the Commission, allowances computed in accordance with the formula prescribed in paragraph (a) of this subparagraph. No allowance for funds used during construction charges shall be included in these accounts upon expenditures for construction projects which have been abandoned.

The Commission's rule on the USOA for electric utilities states, in part, as follows:

> 4 CSR 240-20.030 Uniform System of Accounts-Electrical Corporations
> Purpose: This rule directs electrical corporations within the commission's jurisdiction to use the uniform system of accounts prescribed by the Federal Energy Regulatory Commission for major electric utilities and licensees, as modified herein. . . .
> (4) In prescribing this system of accounts, the commission does not commit itself to the approval or acceptance of any item set out in any account for the purpose of fixing rates or in determining other matters before the commission. This rule shall not be construed as waiving any recordkeeping requirement in effect prior to 1994.
> (5) The commission may waive or grant a variance from the provisions of this rule, in whole or in part, for good cause shown, upon a utility's written application.

On February 4, 2009, the Iatan Unit 1 turbine tripped during start-up activities due to vibration in the turbine that was beyond its operating parameters. This event occurred following the replacement of the high pressure turbine by KCPL's contractor General Electric ("GE"). The turbine replacement and costs associated with the turbine incident were not within the scope of the Iatan Unit 1 AQCS project and are similar to other capitalized maintenance costs. The unit was repaired and returned to availability for in-service testing on March 9, 2009. The 33 day delay of the unit's ability to perform in-service testing increased the amount of AFUDC accrued on the balance of Iatan Unit 1 plant in construction as the Iatan Unit 1 AQCS could not be declared in-service until April 19, 2009. Staff proposed to remove the incremental AFUDC accrued from the Iatan Unit 1 AQCS project and charge it to the work order that captured the costs for the turbine trip.

On July 7, 2009, Staff filed its "Motion to Open Incident Investigation Case" requesting the Commission to open a case for the purpose of receiving an Incident Report pertaining to Staff's investigation of the February 4, 2009 incident at Unit 1 of the Iatan Generating Station. In "Staff's Incident Report" dated January 29, 2010 in Case No. ES-2010-0009, Staff states that:

> It is not the purpose of this report to make any determination regarding the prudence or imprudence of the actions of KCPL or GE with respect to this incident.

Although Staff made no determination of the prudence of KCPL's actions concerning the February 4, 2009 incident in Case No. ES-2010-0009, KCPL's response to Staff Data Request No. 721 in Case No. ER-2009-0089 suggests that both KCPL and GE had some responsibility for the incident:

> ** ____
> ____
> ____
> ____
> ____

____

____

____

____

__________________ **

To Staff's knowledge, KCPL did not pursue recovery from GE of the additional financing costs incurred because of the turbine trip. Based on the excerpt from KCPL's response to Staff Data Request No. 721 above, it appears KCPL accepted approximately 50% of the responsibility for the rotor incident. The total amount of additional AFUDC accrued on GMO's portion of the Iatan Unit 1 AQCS project due to the delay caused by the rotor incident was ** _______ **. GE took responsibility for half the costs of the turbine trip, yet KCPL did not pursue GE for the additional AFUDC costs incurred due to the rotor incident.

Staff has made no adjustment to the actual costs of the turbine incident or the consequent repair and return to service of the turbine. However, given the apparent responsibility of both KCPL and GE, Staff sees no reason to include in the Iatan Unit 1 plant balance the proposed transferred amount of AFUDC proposed in Staff's "Construction Audit and Prudence Review" in the work order capturing the costs of the turbine incident. The AFUDC represents GMO's carrying cost and profit directly attributable to the turbine trip. GMO will make a recovery of and on the capitalized costs of the turbine incident but should not also receive the incremental AFUDC caused by the turbine incident.

Staff Expert/Witness: Keith A. Majors

<u>11. Demand-Side Management Cost Recovery</u>

KCP&L Greater Missouri Operations Company ("GMO") had limited demand-side programs prior to its acquisition by Great Plains Energy. However, since its acquisition by Great Plains Energy, demand-side programs consistent with the demand-side programs of

Kansas City Power & Light Company ("KCPL") have been successfully implemented in both MPS & L&P. On September 15, 2010, Staff provided to the Commission a Status Report concerning all of the Missouri investor-owned natural gas and electric utilities' demand-side programs advisory groups and collaboratives (File No. AO-2011-0035). Attached to this Staff Report as Appendix 6, Schedule JAR-1 are pages from the Status Report, which highlight the GMO Advisory Group[44] process and the challenges and successes to date of GMO's demand-side programs.

GMO's overall spending levels for demand-side programs have approximated the spending goal of one percent of annual revenues to implement cost-effective demand-side programs ordered and approved in stipulation and agreements in GMO's 2007 general rate case (Case No. ER-2007-0004) and in GMO's 2007 Chapter 22 Electric Utility Resource Planning compliance filing (Case No. EO-2007-0298). Further, as reported by GMO for the September 15, 2010 Status Report filing, through June 30, 2010 the total budget for all GMO demand-side programs is $12,036,668 and the actual total expenditures through this period are $10,564,587, or 12% less than budget. Such "under spending" is normal during the early years of demand-side programs' implementation, as a utility's customers become familiar with newly offered demand-side programs and decide to take actions necessary to participate in demand-side programs.

The energy and capacity impacts and the overall delivery processes of the programs are still being evaluated, measured and verified by a third-party contractor of GMO and will be provided to the GMO Advisory Group members along with copies of completed program evaluation reports. The results of future evaluation reports are not expected to impact this case

[44] The GMO Advisory Group includes Staff, Public Counsel, Missouri Department of Natural Resources and other interested parties and serves as an advisory group to GMO in the development, implementation, monitoring and evaluation of the GMO's demand response, energy efficiency and affordability programs.

(see the **DSM Costs** section and the **Demand-Side Management Prudence** section of this Staff Report)

It is Staff's understanding that GMO is not accepting new applications for its large customer MPower demand-response program due to a reduction in the GMO load forecast, which GMO attributes to the current economic recession. It is Staff's understanding that GMO intends to continue offering services of its other energy efficiency, demand response and affordability programs to meet customer demand for these programs. Staff and other parties continue to be engaged with GMO as part of the GMO Advisory Group process to provide advice on the GMO's demand-side programs and as part of the stakeholder group for GMO's Chapter 22 Electric Utility Resource Planning process.

The ordered and approved Stipulation and Agreement as to Certain Issues in Aquila, Inc.'s, n/k/a GMO's, 2007 general rate case (File No. ER-2007-0004) includes the following:

> 11. **Demand Side Management ("DSM") Program Costs.** The signatories agree that for ratemaking purposes Aquila will defer the costs of DSM programs in Account 186 and calculate allowance for funds used during construction (AFUDC) annually. DSM programs are defined as demand response and energy efficiency programs. The prudently-incurred cost included in the Account 186 balance will be amortized over a ten (10) year period. When new rates go into effect reflecting amortization recovery as a result of future general rate proceedings, the prudently-incurred costs included in the Account 186 balance will be added to rate base, Aquila will stop accruing AFUDC on the amount included in rate base, and Aquila will begin amortizing the balance. Additional DSM program costs incurred after the effective date of a final Report and Order in the initial general rate proceeding following Case No. ER-2007-0004 will be treated in the same manner, but will be deferred in a different sub-account by vintage.

The direct testimony of Company witness Tim M. Rush in this general rate proceeding includes a request for continuation of the current accounting treatment of GMO's DSM programs' costs and amortization over ten years of these costs. Staff is in support of this request (see the **DSM Costs** section of this Staff Report).

The "Missouri Energy Efficiency Investment Act" (MEEIA) was established in Senate Bill 376 and became law on August 28, 2009. During 2009 and 2010, Staff organized a stakeholder process including a series of workshops to obtain stakeholder input and to promulgate rules in compliance with MEEIA (File No. EW-2010-0265). Staff subsequently filed proposed MEEIA rules with the Commission in File No. EX-2010-0368. On October 4, 2010, the Commission sent the proposed MEEIA rules to the Office of the Secretary of State. The proposed MEEIA rules were published in the *Missouri Register* on November 15, 2010, and the Commission has scheduled a hearing regarding the proposed MEEIA rules for December 20, 2010.

Staff has evaluated the typical timeline for rulemakings established in Chapter 536, RSMo, and concludes that a final order of rulemaking for the MEEIA rules can be reasonably expected so that MEEIA rules will first be effective June 2011, which may be after the June 4, 2011 requested effective date of the Company's new tariffs in this general rate proceeding. It is unlikely that MEEIA rules will be effective in enough time prior to the effective date of new tariffs in this general rate proceeding to allow time for consideration of the MEEIA rules in this general rate proceeding. Staff, therefore, believes effective MEEIA rules can have no direct impact on the treatment of demand-side program costs in this general rate proceeding.

However, with the passage of Senate Bill 376 and the enactment of MEEIA, the State of Missouri has declared and directed the following:

> 3. It shall be the policy of the state to value demand-side investments equal to traditional investments in supply and delivery

> infrastructure and allow recovery of all reasonable and prudent costs of delivering cost-effective demand-side programs. In support of this policy, the commission shall:
>
> (1) Provide timely cost recovery for utilities;
>
> (2) Ensure that utility financial incentives are aligned with helping customers use energy more efficiently and in a manner that sustains or enhances utility customers' incentives to use energy more efficiently; and
>
> (3) Provide timely earnings opportunities associated with cost-effective measurable and verifiable efficiency savings.
>
> 4. The commission shall permit electric corporations to implement commission-approved demand-side programs proposed pursuant to this section with a goal of achieving all cost-effective demand-side savings. Recovery for such programs shall not be permitted unless the programs are approved by the commission, result in energy or demand savings and are beneficial to all customers in the customer class in which the programs are proposed, regardless of whether the programs are utilized by all customers. The commission shall consider the total resource cost test a preferred cost-effectiveness test. Programs targeted to low-income customers or general education campaigns do not need to meet a cost-effectiveness test, so long as the commission determines that the program or campaign is in the public interest. Nothing herein shall preclude the approval of demand-side programs that do not meet the test if the costs of the program above the level determined to be cost-effective are funded by the customers participating in the program or through tax or other governmental credits or incentives specifically designed for that purpose.

Subsections 393.1075.3 and 4, RSMo. Supp. 2009.

While Staff does not view GMO's existing demand-side programs presently to be demand-side programs proposed pursuant to section 393.1075.4 RSMo. Supp. 2009 and since GMO did not ask for different treatment of demand-side cost under MEEIA, current accounting treatment of GMO's demand-side programs' costs and the amortization over ten years of these costs as discussed in this section and in the **DSM Costs** section of this Staff Report should be continued until the Commission has rules in effect to implement MEEIA.

Staff Expert: John A. Rogers

12. Demand-Side Management Prudence

The Demand-Side Management (DSM) Account 182-440 contains costs that have been incurred for thirteen (13) DSM programs[45] that are in various stages of development and implementation, along with (1) costs not directly assignable to any individual program, and (2) DSM market research costs. At this time, Staff has no recommended disallowances to the levels of costs charged to GMO's DSM Account.

As approved in stipulation and agreements and ordered by the Commission in Case Nos. ER-2007-0004 and EO-2007-0298, the GMO Advisory Group provides suggestions and advice to the Company on DSM program selection and other issues with a funding goal of one percent of annual revenues to implement cost-effective energy efficiency programs by 2010. Combined meetings of the GMO Advisory Group and the Kansas City Power & Light Company (KCPL) Customer Programs Advisory Group (CPAG) include Staff, Office of the Public Counsel, Department of Natural Resources and other interested parties. Based on Staff's participation in the Advisory Group meetings and Staff's review of the costs in Account 182-440, Staff discovered no evidence of imprudence regarding the level of costs charged to the DSM programs.

Staff Expert/Witness: Hojong Kang

13. DSM Costs

Staff has included the unamortized June 30, 2010 DSM costs for MPS and L&P in rate base. These DSM deferrals are being amortized over ten (10) years consistent with the treatment afforded these costs in prior rate cases.

Staff Expert: Charles R. Hyneman / Hojong Kang

[45] DSM programs consist of demand response, energy efficiency and affordability programs, including the low income weatherization programs.

14. Low Income Programs

a. Economic Relief Pilot Program

KCP&L Greater Missouri Operations Company (GMO or Company) Economic Relief Pilot Program (ERPP) began September 1, 2009. It was approved by the Commission in ER-2009-0089 as a three (3) year pilot program. It is designed to study the ability to create an energy credit benefit to GMO's qualifying low-income residential customers. The ERPP was designed to pay up to fifty dollars per month to low-income customers in the form of a "fixed credit" that would appear on the participant's current bill. The purpose of the "fixed credit" applied monthly would be an attempt to make the bill more affordable for the customer with the hope that the customer would remain current on their electric utility bill. The tariff also stated that an evaluation of ERPP may be in any Company rate or complaint case and that the evaluation shall be by an independent third party evaluator under contract with the company that would be acceptable to the Company, Commission Staff and the Public Counsel. In addition, the ERPP pilot Agreement allowed GMO to defer fifty percent of the cost of the program until GMO's next rate case.

Staff Expert/Witness: Carol Gay Fred

i. Recommendation

Based on Staff's review of GMO's witness Jimmy Alberts' testimony and GMO's responses to public counsel data request Staff received, Staff recommends continuation of the ERPP program for the life of the pilot program but strongly recommends that GMO acquire an independent third party evaluator of the program. Until this task is accomplished, Staff recommends not allowing GMO to recover fifty percent of the cost of the program at this time. Staff bases this recommendation on three points:

1. In the initial design of ERPP, was to include one thousand customers from KCPL territory and one thousand from GMO territory. However, in June 2010 KCPL had enrolled only five hundred and twenty-six (526) KCPL customers and four hundred and seventy-four (474) GMO customers. Staff recognizes that the program only began September 1, 2009, however, nine months later or three quarters of the year from the start-up of the pilot program KCPL and GMO collectively, have only one thousand out of the anticipated two thousand participants enrolled in the program. This does not appear to be sufficient to request cost recovery of deferred cost created by the customers enrolled.

2. The Company has not acquired a third party evaluation study on the program to verify the information or calculation used in this case.

3. In addition, in prior Staff witness Anne Ross' Rebuttal Testimony in Case No. ER-2009-0089, she stated, "Staff believes that a third party evaluation studying the effect of the program on the Company's bad debt level should be a condition of the Company recovering any program funds in future rate or complaint case proceedings. Due to the necessity of collecting adequate pre-and post-program usage information on participants, it may not be possible to evaluate the program in the next rate or complaint proceeding, in which case the decision as to whether the Company would be allowed to recover these deferred expenses should be delayed until a program evaluation is performed."

The Commission should allow the continuation of the ERPP for the full three (3) year life of the program; however, Staff would make the following additional recommendations:

- Acquire an independent third party evaluator for the program to track all aspects of the program for weaknesses, strengths and improvement opportunities.

- Work more extensively with Salvation Army to ensure capacity enrollment of ERPP.

- Improve on education and providing awareness of ERPP with other Energy Assistance Agencies of the availability of ERPP, i.e., United Services Community Action Agency, 211, St. Vincent de Paul, etc.

- Provide SA field staff availability to AgencyLink, the web based interface that allows registered social service agencies access to restricted and highly limited view of customer information in order to assess account status and only the information required to make a determination to qualify customers for ERPP and other agency payments.

- Continue to conduct as many as feasible Connections campaign Energy Resource Fairs on an annual basis.

Staff Expert/Witness: Carol Gay Fred

ii. Qualifying Criteria

The program was designed to help residential low-income customers whose annual household income is no more than 185% Federal Poverty Level (FPL) as established by the poverty guidelines updated periodically in the Federal Register by the U.S. Department of Health and Human Services under the authority of 42 U.S.C. 9902 (2).

Participants account must be current or those who have an outstanding arrearage must enter into a special payment arrangement as mutually agreed to by both Participant and Company.

Participants must have not current or historical mishandling of their account, i.e., tampering, non-payment or diversion.

Participants must complete an interview or questionnaire, of information related to their energy use and program participation.

Participants will not be subject to late payment penalties while participating in the program.

Participants must apply for Low-Income Energy Assistance Program (LIHEAP) grant and any other energy assistance programs identified by the Company.

Staff Expert/Witness: Carol Gay Fred

iii. Credits

Participants shall receive the available ERPP credit as long as the participant continues to meet the ERPP eligibility requirement and reapplies to the program annually.

The credit amount is not to exceed $50 per month. The credit amount will be determined by the Company the time of enrollment.

Staff Expert/Witness: Carol Gay Fred

iv. Arrearages

Participant will enter special pay agreements as mutually agreed to by both the Participant and the Company.

Staff Expert/Witness: Carol Gay Fred

v. Billing Periods

The credit will appear on each monthly bill, enabling the Participant can see the savings to his account and any arrearage elimination once accomplished.

Staff Expert/Witness: Carol Gay Fred

vi. Education

Education for the ERPP program, as well as other options available to the consumers, is part of an education and outreach campaign called "Connections." It appears the "Connections" program was designed to be an education outreach program to provide customers a local presence in the communities where they live as a one-stop-shop, direct face-to-face interaction, allowing an opportunity to discuss account specific questions and solutions. It was also seen as a way to partner with other community organizations, i.e, Salvation Army, United Way 2-1-1, and KCMO Weatherization initiative. Through this program, KCPL also hosts Connections Energy Resource Fairs, Back to School Fairs, etc. There is also an exclusive 800-number during the Connections campaign to support customers unable to attend a local program.

Staff Expert/Witness: Carol Gay Fred

vii. Program Administration

KCPL contracted with Salvation Army (SA) as their partnering agency who has an established presence in the community, to act as the gatekeeper. SA processes the ERPP applications, however, KCPL reviews the applications submitted by SA to determine if the applicant meets all criteria to be a program participant. There are two primary barriers to the initial participation; 1) marketing to customers and 2) communications methodology with SA, specifically to SA outlying field offices.

Staff Expert/Witness: Carol Gay Fred

b. Low-income Weatherization

Staff recommends that GMO continue to provide annual funding of $150,000 for low-income weatherization, as currently allocated between the weatherization agencies. Staff also recommends that GMO change its distribution method for the weatherization funds from monthly direct reimbursement to the Weatherization Agencies to an annual deposit of the funds to a The Missouri State Environmental Improvement and Energy Resources Authority (EIERA) account.

There are specific programs designed to help low-income customers with energy conservation. Low-income consumers often live in housing that is energy inefficient with substandard insulation and other deficiencies. These customers would benefit from building shell energy conservation measures such as weatherization or more energy-efficient appliances.

The Low Income Weatherization Assistance Program ("Weatherization Program") is administered by the Missouri Department of Natural Resources ("MDNR") using federal, state, and utility funding. The Weatherization Program is administered locally by Community Action Agencies or other local agencies ("Weatherization Agencies"). In the GMO service area, the Weatherization Program is administered by the Kansas City Housing and Community Development Department, the Missouri Valley Community Action Agency, the Community Services Inc., the West Central Missouri Community Action Agency and the Green Hills Community Action Agency.

The federal government, through the American Recovery and Reinvestment Act ("ARRA"), is providing special funding of $128 million for the Missouri Weatherization Program for the period of April 2009 – March 2012 ("ARRA Period"). The ARRA provides an average of $6,500 of weatherization for households with income at 200% or less of the Federal Policy Guidelines. In the previous three year period (2006-2008), prior to the ARRA Period, federal funding for the Missouri Weatherization Program was approximately $18 million and the average amount of weatherization per household was $3,000. The amount of weatherization has increased has increased from about $3,000 to $6,500 per household. The Weatherization Agencies are making a concerted effort to utilize the ARRA funding before the March 2012 deadline.

According to an August 31, 2010, *Customer Program Expenditures* spreadsheet furnished to the *GMO Demand-Side Management Advisory Group* (DSMAG), attached as Appendix 7, Schedule HEW - 1, the weatherization agencies have only used ** ____ ** of the 2007 through 2010 budgeted funds for weatherization. This under-utilization of funds is primarily because of the agencies' focus on using the ARRA funding and restrictions on ARRA funds being combined with utility funds. At the end of the ARRA period the Weatherization Agencies anticipate using any surplus utility funds to maintain their level of weatherization activity.

The Missouri State Environmental Improvement and Energy Resources Authority ("EIERA") was established to manage and disburse federal and other weatherization funds for MDNR to the Weatherization Agencies according to MDNR guidelines. Currently four other Missouri jurisdictional utilities utilize the EIERA to manage their weatherization funds. The

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funds at the EIERA are invested to earn a return until they are distributed so the value of the funds is enhanced.

Staff recommends that the unutilized low-income weatherization funds be placed in an account with EIERA. In addition, in order have some additional GMO funds for weatherization when the ARRA funds are no longer available, Staff recommends that GMO continue to provide annual funding of $150,000 for low-income weatherization, as currently allocated between the weatherization agencies. Staff also recommends that GMO change its distribution method for the weatherization funds from monthly direct reimbursement to the Weatherization Agencies to an annual deposit of the funds to an EIERA account.

Staff Expert/Witness: Henry E. Warren

15. Insurance Expense

Insurance expense is the cost of protection obtained from third parties by utilities against the risk of financial loss associated with unanticipated events or occurrences. Utilities, like non-regulated entities, routinely incur insurance expense in order to minimize their liability associated with unanticipated losses for property assets and personal injury from accidents. Certain forms of insurance reduce ratepayer's exposure to risk. Premiums for insurance are normally pre-paid by utilities; i.e., payment is made by the utility to the insurance vendor in advance of the policy going into effect. These insurance payments are normally treated as prepayments, with the amount of the premium being booked as an asset and amortized to expense ratably over the life of the period the insurance is in force. The unamortized balance of the prepaid insurance account (either the period-ending balance or a 13-month average balance) is included in rate base, with an annualized level of insurance expense included in rates.

During the audit, Staff reviewed the Company's insurance policies for the following forms of insurance:

- Crime
- Fiduciary Liability
- Directors and Officers
- General Liability/Umbrella
- Excess Directors & Officers
- Excess Liability
- Excess fiduciary
- Workman's Compensation
- Excess Workman's Compensation
- Property
- Labor Management Trust Fiduciary
- Auto Liability
- Bonds

Staff reviewed the policies and verified the current insurance premiums for each insurance type. An annualized amount was determined and allocated to MPS & L&P. The MPS adjustments E-133.1 and E-134.4 and L&P adjustments E-138.1 and E-139.4 reflects the annualized levels for GMO's portion of the insurance costs.

Staff Expert/Witness: Karen Lyons

16. Injuries and Damages

Injuries and damages relate to insurance claims that are not covered by insurance policies. Injuries and damages usually consist of claims associated with general liability, workman's compensation, and auto liability. Staff analyzed five years of data and determined a three-year average, including the period of 2007 through 2009, using the actual cash payments to normalize the Company's costs associated with injuries and damages. The actual cash payments are those paid to individuals who had an injury and claim. As a result of these injuries, MPS and L&P made cash settlements. A three year average was used based on the data received from the Company. The MPS adjustment E-134.3 and L&P adjustment E-139.3 reflects a normalized level of costs for injuries and damages.

Staff Expert/Witness: Karen Lyons

17. Rate Case Expense

Rate case expenses are costs incurred by a utility in preparation and performance of its filing for a rate case. In the instant case, GMO has incurred expenses in conjunction with legal counsel, regulatory consulting and outside consultants.

Staff usually treats rate case expense as a normalized expense necessary to provide utility service. This treatment involves determining the cost to process a rate case on a normalized level and reflecting that cost in the cost of service over the period of time between rate cases.

Staff requested invoices to support the amount of rate case expense charged to GMO in Data Request No. 154 in File No. ER-2010-0356. Staff received a list of the invoices with the amounts charged to rate case expense but did not receive any copies of invoices. Staff has issued additional discovery to obtain copies of the invoices GMO has identified as rate case expense.

In Staff's Direct filing in File No. ER-2010-0355, Staff proposed to transfer the costs charged to rate case expense that would more appropriately be charged to Iatan Unit 1 or 2. Staff expects to apply this same treatment to GMO rate case expenses. However, Staff in this case has no invoices to support any level of rate case expense in its direct filing. Staff will include all prudent and reasonable costs incurred and paid through the true-up of the current rate case, File No. ER-2010-0356, separated between costs more appropriately charged to rate case expense and those that should be charged to the Iatan Construction Projects.

Staff did include an amortization of the depreciation study over 5 years as included in rate case expense in Case No. ER-2009-0090.

Staff Adjustment E-140.4 reflects a 5 year amortization of the depreciation study in Case No. ER-2009-0090 for GMO. Staff Adjustments E-140.1, E-140.2, and E-140.3 remove the test year amortizations of rate case expenses from the 2005, 2007, and 2009 rate cases for MPS.

Staff Adjustments E-147.1, E-147.2, and E-147.3 remove the test year amortizations of rate case expenses from the 2005, 2007, and 2009 rate cases for L&P.

Staff Expert/Witness: Keith A. Majors

18. Public Service Assessment Fee/FERC Assessment Fee

The Public Service Commission assessment ("PSC Assessment") is an amount billed to each regulated utility operating under the jurisdiction of the Commission. The PSC Assessment is calculation based upon an allocation of the Commission's operating costs for regulating those utilities. GMO's PSC Assessment was annualized using the latest assessment available for the current fiscal year ("FY-2011") on information obtained from the Commission's records. The updated PSC Assessment was compared to the PSC Assessment amount included in GMO's test year to form the basis for the adjustment in Staff's revenue requirement. Staff also updated the Company Federal Regulatory Energy Commission ("FERC") Assessment paid to represent 12 months ending June 30, 2010.

Adjustments MPS: E-138.1 and E-137.1

Adjustments L&P: E-145.1 and E-146.1

Staff Expert/Witness: Bret G. Prenger

19. Transmission Expenses and Revenues Tracker

Staff has completed its review of GMO's transmission expenses and recommends the Commission authorize the Company to use two transmission expense and revenue trackers, one each for MPS and L&P. Additionally, Staff recommends GMO be required to file transmission project cost estimate information in a detailed manner and as the cost estimate of any given transmission project changes, as further described below.

The Company's historic transmission expenses are provided on Schedule TMR2010-4 of Company witness Tim M. Rush for both L&P and MPS. Schedule TMR2010-4 also includes the Company's estimate of its 12-month ending December 31, 2010 transmission expenses for both L&P and MPS that it included in its filing that initiated this case. That estimate of transmission expenses includes estimated transmission expenses for July through December 2010 and three adjustments described in the pre-filed Direct Testimony of Company witness John P. Weisensee from line 10 on page 30 to line 17 on page 31 (Adjustment CS-45) and from line 20 on page 41 to line 20 on page 43 (Adjustments CS-85 and CS-86). Staff has summarized those Company adjustments as follows:

- Adjustment CS-45: Annualized expected transmission costs in FERC account 565 based on: 1) expected increased transmission expenses primarily due to increased off-system sales made possible by Iatan Unit 2, and 2) projected costs related to SPP base plan upgrades to meet the mandatory North American Electric Reliability Corporation and SPP reliability standards, which call for one-third of each base plan project to be shared by all SPP members and the remaining two-thirds of the project cost to be allocated among the members that directly benefit from the project.

- Adjustment CS-85: Annualized Missouri regulatory assessments and FERC Schedule 12 fees based on assessment levels projected to be in effect in December 2010. Under this new procedure, FERC will begin to base its assessment on all load under SPP rates including retail load served by member companies and will bill SPP for the assessment. SPP will then pass a share of this cost through to all point-to-point and network service customers it serves.

- Adjustment CS-86: Annualized SPP Schedule 1-A fees based on the annual funding levels expected to be in effect on December 31, 2010 and on the Company's share of load at the time of the twelve monthly system peaks. The Schedule 1-A fees are for SPP activities related to regional transmission planning, processing and studying transmission and generation interconnection service requests, managing congestion across the transmission system, administering the SPP transmission tariff, serving as a reliability coordinator, managing the power reserve sharing system and operating the regional energy imbalance market.

The annual amounts of the Company's historic and estimated test year transmission expenses for MPS and L&P the Company provides in its filing that opened this case are:

Transmission Expenses [46]

($000)						
Year	2005	2006	2007	2008	2009	Est. 2010
MPS	$12,177	$22,674	$19,909	$22,344	$14,210	$17,228
L&P	$4,174	$4,902	$4,936	$5,416	$3,459	$1,409

Staff has completed its review of the Company's transmission expenses and recommends the Commission authorize the Company to use a transmission expense and revenue tracker. Staff recommends the Company be authorized to use a transmission expense and revenue tracker due to the historical growth in and current high level of the Company's transmission expenses, the uncertainty in the levels of its future transmission expenses, and because the Company has less control over the level of transmission expenses the SPP assigns to it than the Company has over most of its other expenses. While Staff does agree that the Company has less control over some of its transmission costs, Staff does assert that the Company has control over the transmission expenses it incurs related to transmission it, or its affiliates, directly constructs.

The uncertainty of the Company's future transmission expenses is increased by the recently FERC approved "Highway Byway" cost allocation tariff filing, which will increase the percentage of costs of newly planned transmission throughout the SPP region that will be

[46] Including FERC Account Numbers 561400, 561800, 565000, 565020, 565021, 565027, 565030, 575700 and 928003. Note that Staff has proposed a different transmission tracker amount.

allocated to the Company. For example, the Company will be allocated approximately 4% of all transmission planned in the SPP footprint above 300 kilo-Volt (kV).

SPP has also approved a higher level of transmission expenses than normal in the recent past, and Staff expects this trend to continue. For example, in April 2010, SPP approved $1.4 billion of transmission expenses in its "Priority Projects." Staff does expect additional transmission valued at over $1 billion to be planned by SPP in its new Integrated Transmission Planning Year 20 ("ITP20"), consisting of transmission at, or possibly about, 345 kV, which is most likely to be voted on for approval by the SPP Board in January 2011. Approval of ITP20 would lead to an increase in expected future transmission expenses for the Company, although the exact amount of those expenses is unknown at this time. Transmission project cost estimates may also differ significantly from the final cost of these projects when built, increasing the uncertainty of the future level of the Company's transmission expenses.

The full transfer of control of GMO's transmission system to participate in all functions of the Southwest Power Pool (SPP) regional transmission organization was finalized on June 18, 2009. On this date, the Federal Energy Regulatory Commission's (FERC) order accepting the "Agreement for the Provision of Transmission Service to Missouri Bundled Retail Load" was effective (retroactive to April 15, 2009), allowing the Company to exercise the authority granted to it by the Missouri Public Service Commission (Commission) in Case No. EO-2009-0179.

While GMO may have less control over expenses assigned to it by SPP than other expenses it incurs, Staff expects and encourages GMO to work within the SPP stakeholder process to advocate for transmission improvements that benefit GMO stockholders and GMO ratepayers, and to advocate for a proper allocation of transmission expenses. Staff also expects that GMO's representatives advocate in GMO's and its customer's best interest if that interest is different from its affiliate Kansas City Power & Light Company ("KCPL"). Staff notes that GMO's voice on the Members Committee of SPP is that of the representative of its affiliate KCPL, Michael L. Deggendorf, KCPL's Senior Vice President-Delivery.

In those situations where GMO has direct control over the transmission expenses it incurs, Staff recommends the Commission require GMO to file with the Commission the information shown in Appendix 8, Schedule DIB - 1, and provide the same information that is supplied to SPP, when GMO proposes a transmission project at a voltage greater than 100 kV, and that GMO be required to update that filing within seven days of when the project cost estimate is changed each time the project cost estimate changes by more than 10% from the last cost estimate GMO filed with the Commission. In addition, Staff recommends the Commission order the Company to file quarterly updates of the costs incurred and progress made towards completion of all transmission projects.

If off-system sales change in this instant case, then there should be a corresponding adjustment to GMO's transmission expenses included in any transmission expense and revenue tracker related to off-system sales. In prior rate cases involving GMO, as well as in those involving its affiliate KCPL, during the case, the levels of off-system sales proposed have changed dramatically. In the current economic conditions Staff believes this is very likely to happen again in this rate proceeding. Staff will continue to review transmission expenses and proposed off-system sale levels, and propose any appropriate adjustment to transmission expenses based on changes in off-system sales levels.

Staff recommends a transmission expense and revenue tracker include two FERC Accounts included as "revenue credits" in the Company's FERC Transmission formula rate filing: FERC account 454.0001 "Rent From Electric Property" (to the extent derived from transmission); and FERC account 456.1 "Revenues from Transmission of Electricity for Others", listed in the FERC Formula Filing as "New 456.1 Account Activity". Staff recommends that the revenues from these accounts be used to negatively adjust the amount in FERC Account 565.000.

Worksheet "A-1 Revenue Credits" from the GMO's FERC Formula Rate Spreadsheet[47], updated as of 9-28-10, is attached as Appendix 8, Schedule DIB-2. The relevant account names and totals have been highlighted. These totals are for GMO (both L&P and MPS).

In order to divide the amount of the revenue credits between L&P and MPS, Staff proposes using the proportion of the Zonal "Annual Transmission Revenue Requirement" ("ATRR") that L&P and MPS had before GMO's FERC Formula Rate Filing. The Zonal ATRRs are shown on Appendix 8, Schedule DIB – 3, on page DIB-3-2.

The calculation of the proportions is shown on Appendix 8, Schedule DIB-4, along with the amounts of (1) FERC account 454.0001 "Rent From Electric Property" (to the extent derived from transmission); and (2) FERC account 456.1 "Revenues from Transmission of Electricity for Others", listed in the FERC Formula Filing as "New 456.1 Account Activity" to assign to L&P and MPS.

For the amounts updated 9-28-10, FERC account 454.0001 "Rent From Electric Property" (to the extent derived from transmission) and the "Net 456.1 Account Activity" are as follows:

[47] The inclusion of information from the Company's formula rate spreadsheet does not constitute Staff taking a position on the Company's formula rate.

Revenue Description	"Net 456.1 Account Activity"	FERC account 454.0001 "Rent From Electric Property" (to the extent derived from transmission)
Staff Adjustment	Staff Adjustment 1	Staff Adjustment 2
L&P	$1,615,534	$80,336
MPS	$3,389,963	$168,573
GMO (L&P + MPS)	$5,005,497	$248,909

In Staff Report in File No. ER-2010-0355 regarding Staff's recommendation for the creation of a transmission expense and revenue tracker, Staff inadvertently used the revenue credits for KCPL for both its Missouri and Kansas jurisdictions. Staff will file an updated corrected version of its transmission tracker recommendation with the correct revenue credit amount for KCPL's Missouri jurisdiction.

Appendix 8, Schedule DIB-5 lists the differences between the transmission tracker proposed by GMO in its direct testimony and the transmission expense and revenue tracker Staff proposes. The proposed amount of Staff's transmission expense and revenue tracker is ($286,822) for L&P and $13,669,875 for MPS. The amount of FERC account 456.1 "Revenues from Transmission of Electricity for Others", listed in the FERC Formula Filing as "New 456.1 Account Activity", is listed as Staff Adjustment 1. The amount of FERC Account 454.0001 "Rent From Electric Property" (to the extent derived from transmission) is listed as Staff Adjustment 2.

Staff recommends that the transmission expense and credit amounts included in GMO's revenue requirements for setting rates for MPS and L&P in this rate proceeding be based on the true-up amount for the 12-months ending December 31, 2010 for (1) the expenses in the accounts listed on Company witness Tim M. Rush's Schedule TMR2010-4; and (2) the revenues in FERC Account 454.0001 (to the extent derived from transmission) and FERC account 456.1

that would be listed in the FERC Formula Filing as "New 456.1 Account Activity", as relevant to L&P and MPS .

Staff proposes GMO should track its actual transmission expenses separately for MPS and L&P on an annual basis. Staff further recommends the revenues from the two Staff Adjustments listed above also be tracked on an annual basis. Also, Staff recommends these expenses and revenues be tracked separately for L&P and MPS. Staff proposes that GMO record any annual excess amount above the transmission expenses amount included in the revenue requirement used in setting rates in this rate proceeding as a regulatory asset (account 182) and any annual shortfall below the transmission expenses amount in rates in this rate proceeding as a regulatory liability (account 254) for each L&P and MPS. Staff recommends the regulatory asset or regulatory liability be amortized over five years in the Company's next rate proceeding, with the unamortized balance included in rate base.

Staff Expert/Witness: Daniel I. Beck

20. Smart Grid Demonstration Project

Staff is not aware of any advanced metering infrastructure (AMI) or Smart Grid applications in the GMO service territory.

Staff Expert/Witness: Randy S. Gross

IX. Depreciation

A. Recommendation

Staff recommends that the Commission order GMO to:

1. Use the depreciation rates described in Appendix 9, Schedules AR-MPS-1 for MPS, AR-L&P-1 for L&P, and AR-ECORP-1 for ECORP.

2. Record amortizations as shown in Appendix 9, Schedules AR-MPS-1 and AR-L&P-1 against plant accumulated depreciation reserve accounts to correct for

over or under accrued depreciation reserves. Staff does not recommend additional amortization of ECORP depreciation reserve at the time of this direct filing.

3. Record all plant cost of removal and salvage by FERC account, date, and location unit code in a permanent continuous record, including cost of removal and salvage for production units previously removed from service. Include in this record a differentiation between interim and final retirements and net salvage.

Staff's recommendation results in GMO's total annual depreciation expense of approximately $71,400,000, based on approximate depreciation expenses of $49,000,000 for MPS, $17,700,000 for L&P, and $4,700,000 for ECORP, and a reduction in excess accumulated depreciation reserves of approximately $5,600,000 total GMO annually, based on $3,000,000 for MPS and $2,600,000 for L&P.[48],[49] Total GMO accumulated depreciation reserve is estimated to have accrued $166,000,000 more than the appropriate reserve balance, $92,000,000 for MPS and $74,000,000 for L&P, as shown in Appendix 9, Schedules AR-MPS-2 and AR-L&P-2.

Staff's recommended depreciation rates shown in Appendix 9, Schedules AR-MPS-1, and AR-L&P-1 for MPS and L&P are based on the following:

1. Treatment of all Steam and Other production, Transmission, and Distribution accounts as living accounts[50], with mass property[51] analysis and whole life[52] depreciation rates.

2. General plant accounts 391, 393, 394, 395, 397, and 398[53] have been left at the current ordered rates for MPS and L&P, pending identification by KCPL of retirements associated with recent office consolidations and relocations.

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[48] The amortization results in a depreciation expense comparable to the use of remaining life rates. The depreciation amortizations shown on Schedules AR-MPS-1 and AR-L&P-1 are calculated as the difference in annual accruals obtained when using remaining life versus whole life depreciation rates for each plant account. This results in a fixed amortization using December. 31, 2008 plant and reserve balances as the basis for determining over or under accrued reserves. Iatan additions in 2010 for L&P do not result or require modification to these amortizations.

[49] **Remaining life**: Straight line depreciation over the composite remaining life of an account with corrections for existing accumulated reserves imbalances.

[50] **Living Accounts**: Groups of property which may experience interim retirements, but for which retired property is expected to be replaced by comparable property, with or without improvements in technology.

[51] **Mass Property**: Continuous living group of property where only small routine replacements occur.

[52] **Whole Life**: Straight line depreciation over whole composite life of an account without any correction for existing accumulated reserve imbalances.

3. Assignments of depreciation reserve amortization to correct for over or under accrued accumulated depreciation reserves.

Staff's recommended depreciation rates shown in Appendix 9, Schedules AR-ECORP-1 are based on retaining the current ordered rates from Case No. ER-2005-0436 pending identification by the Company of retirements associated with recent office consolidations and relocations.

B. Regulatory Depreciation

Staff's recommended rates for MPS, ECORP, and L&P are based on past retirement history, with influence from retirement histories of similar utility companies and future plant operation expectations. Staff's objective in recommending rates is to match the rate of money collection from ratepayers with the consumption of utility plant using a straight line estimate of the life time cost of the plant utilized to provide the service.[54] Staff's depreciation rates are

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[53] **General plant accounts 391, 393, 394, 395, 397, and 398**: General office electronic, computer, communication, laboratory, and miscellaneous equipment

[54] The book keeping associated with regulatory depreciation expense is to:
a) Allocate and record the money collected from ratepayers for depreciation purposes to specific plant accounts,
b) Account for the consumption of the invested capital as plant equipment is retired from service,
c) Account for the cost of removal, salvage value received, and any third party payments such as insurance proceeds,
d) Provide a continuous and consistent method of recording of the above listed costs as a historical record for use in future depreciation analysis.

The cost of plant in service is recorded as the original installed cost. The installed cost of plant includes costs other than just labor and materials, it also includes costs such as project planning, engineering, sales taxes, transportation, insurance and cost of funds provided during construction, supervision, and all associated overhead costs. This original cost of plant in service stays with the equipment until it is retired from utility service. A transfer of ownership by the Company to another company or set of investors does not alter this cost, regardless of the amount of money paid by the new owners to attain ownership.

Only by order of the Commission may the cost of plant in service, the accumulated depreciation reserve, the depreciation rates, or the recording of depreciation expense be modified. Depreciation expense continues to be recorded and accumulated per Commission order until altered by a subsequent Commission order, even if the plant account in question is considered to be fully depreciated.

Depreciation expense is calculated as a percent of total plant in service for each plant account.

The cost of installed plant is recorded as plant in service on the date the equipment in question is used to provide the utility service.

The recorded cost of plant in service is independent of the source of funds used to pay for the installed plant. The source of funds may be from investors, loans, insurance proceeds, ratepayer or third party contributors, or simply still be accounts payable. The regulatory accounting system outside of the plant in service and depreciation section is used to address these issues.

designed to account for consumption of original cost of plant, the expected cost to remove and dispose of plant at the end of its life, and the expected salvage value received at disposal.

Basic Formulas for Depreciation of Living Accounts:

Depreciation expense = (Depreciation Rate) * (Total Original Cost of Plant in Service)

$$\text{Rate \%} = \frac{100 - (\text{net salvage \%})}{\text{ASL}} = \frac{100}{\text{ASL}} - \frac{\text{Net Salvage \%}}{\text{ASL}}$$

Average Service Life (ASL) is the average number of years the dollars in the account are expected to remain in service. ASL is equal to the area under a survivor curve.[55] When working with living accounts, the survivor curve is not truncated, as it is expected that additional property will be placed into the account to replace property that has been retired.

Net Salvage = gross salvage - cost of removal

$$\text{Net Salvage \%} = \frac{\text{net salvage \$}}{\text{Retirement \$}} * 100 \qquad \text{Averaged}$$

When it is expected that the terminal net salvage rate will be equal to the interim net salvage rate, it is sufficient to use the single (Net Salvage % / ASL) term, as shown above.

C. Depreciation Definitions

Cost of Removal: The cost associated with disposing of a retired unit of property, net of its salvage value.

Life Span: Depreciation analysis method using a fixed life for a specific unit of property.

Living Accounts: Groups of property which may experience interim retirements, but for which retired property is expected to be replaced by comparable property, with or without improvements in technology.

[55] The survivor curve is forecasted using Iowa curves. The Iowa curves are widely accepted models of the life characteristics of utility property. The system of Iowa curves is a family of 176 types of utility and industrial property. The curves were developed at the Iowa Engineering Experiment Station at what is presently known as Iowa State University. The Iowa curves were first published in 1935 and reconfirmed in 1980. The original survivor curve is mathematically and visually matched with various Iowa curves to determine which has the most appropriate fit, either for a significant portion of the curve or just a specified portion of the curve.

Mass Property: Continuous living group of property where routine replacements occur.

Net Salvage: Salvage value minus the cost of removal.

Remaining Life: Straight line depreciation over the composite remaining life of an account with corrections for existing accumulated reserves imbalances.

Whole Life: Straight line depreciation over the whole composite life of an account without any correction for existing accumulated reserve imbalances.

D. Staff's Analysis

Staff performed four depreciation analyses, (Case A, B, C and D) for MPS and L&P in developing its depreciation recommendation for each. The methods and components of each are discussed below, and a summary of the results of each is presented in Appendix 9, Schedules AR-MPS-3, and AR-L&P-3 as well as the Commission's currently-ordered rates for each (Case No. ER-2005-0436). Staff's use of multiple analyses allows for an apples-to-apples examination of the effects of several of the more significant variables in the field of depreciation.

Staff Case A (Included in Appendix 9, Schedules AR-MPS-3 and AR-L&P-3)

Staff's recommends the Commission order GMO to adopt for MPS and L&P the depreciation rates derived in the study labeled Case A for each account. Staff addresses two issues related to accumulated depreciation reserves and depreciation expense with this recommendation:

1. Imbalances in depreciation reserves that have built up over time,[56]
2. Discrepancies in some General plant accounts that may have resulted in erroneous depreciation study results.
3. The large increase in depreciation expense due to the addition of Iatan 2 to plant in service for L&P is not addressed in these depreciation recommendations.

[56] This is in addition to the reserves held for future cost of removal.

Staff's recommended depreciation expense compared with the Company's request for each division is as follows:

Company Division	Staff Proposal	Company Proposal
MPS	$49,057,851	$57,502,543
L&P[57]	$17,719,265	$19,501,888
ECORP	$4,700,530	$7,137,256

For Case A, Staff used the following methods and assumptions:

1. Treatment of all Steam and Other production, Transmission, and Distribution accounts as living accounts, with mass property analysis and whole life depreciation rates,

2. General plant accounts 391, 393, 394, 395, 397, and 398[58] have been left at the current ordered rates, pending identification by the Company of retirements associated with recent office consolidations and relocations and clarification on the accuracy of historical retirement data. For ECORP, account 390 (Structures and Improvements) was added to the list of accounts in question.

3. A depreciation amortization for all over or under accrued accounts was calculated and recommended. The amortization amounts were set at a fixed amount representing over or under accrual as of Dec. 31, 2008, amortized over the calculated remaining life for each account.

4. Depreciation rates were estimated from analysis of Company retirement history, and review of data request responses regarding final retirements and descriptions of assets in specific accounts

Staff Case B

While Staff recommends the Commission authorize KCPL's depreciation rates identified in Staff Case A discussed above, Staff has developed Staff "Case B" depreciation rates that generally uses the same methods for the same accounts that were used to establish the current depreciation rates. Those treatments include:

1. Treatment of all Steam and Other production, Transmission, and Distribution accounts as living accounts, with mass property analysis and whole life depreciation rates. No correction for over or under accrued depreciation reserves.

[57] These comparisons use plant balances as of Dec. 31 2008 with a modification to L&P to include an estimate of Iatan additions for plant placed in service in 2010.

[58] **General plant accounts 391, 393, 394, 395, 397, and 398**: General office electronic, computer, communication, laboratory, and miscellaneous equipment

Staff Case C

While Staff recommends the Commission authorize GMO's depreciation rates identified in Staff Case A discussed above, Staff has developed Staff "Case C" depreciation rates which are derived consistent with the methods used for AmerenUE's depreciation rates adopted by the Commission in File No ER-2010-0036 as requested by AmerenUE. In Case C, Staff used a life span analysis with remaining life rates for all Steam production accounts. Consistent with the approach adopted by the Commission in File No. ER-2010-0036, all other accounts, including Combustion turbines, were treated as living accounts, with mass property analysis and remaining life rates. Use of life span enabled Staff to distinguish interim and final (terminal) retirements, and to separate net salvage into interim and final net salvage. Staff set the rate of terminal net salvage to 0 % consistent with the approach adopted by the Commission in Case No. ER-2010-0036.

Staff Case C differs from GMO's request in the following respects:

1. The removal of terminal net salvage from the life span analysis for the Steam Production accounts,

2. For purposes of calculating the depreciation rates associated with the Company's Steam production accounts, Staff made modest adjustments of retirement dates proposed by the Company by increasing the life span for Iatan 2 from 50 to 60 years and adding three months to all retirement dates,[59]

3. Staff used the Mass Property method for combustion turbine analysis versus the Company proposal that used Life Span.

With these adjustments the annual depreciation expense presented in Case C by Staff for MPS and L&P is approximately $6,500,000 less for MPS and $2,000,000 less for L&P than requested by GMO. Staff does not recommend Case C, but does recommend that if the

[59] The Company proposed dates may be found in Case No. ER-2010-0356 Spanos Direct testimony Schedule JJS2010-1 at page II-27 for MPS and Schedule JJS2010-2 at page II-27 for L&P., Staff increased the assigned retirement dates by three months to revise retirement dates from June (peak load month) to Sept for each planned retirement year.

Commission adopts GMO's requested life span method of analysis for certain accounts that the Commission order the following:

1. The proposed retirement date for Iatan 2 be extended by 10 years, from the Company requested 50 years to a life span of 60 years,

2. All proposed retirement dates for production equipment be extended at least 3 months from June to September of the retirement year.

3. The depreciation analysis for combustion turbines use a mass property method for estimating depreciation rates.

For Case C, Staff used the following methods and assumptions

1. The life span method was used for steam production plant accounts, with retirements and net salvage broken into interim and final components, with terminal net salvage at 0%,

2. Remaining life depreciation rates used for all accounts to compensate for past over or under accruals,

3. Mass property analysis, with remaining life rates, was used for all other accounts, including Combustion turbines,

4. Depreciation rates were estimated from analysis of Company retirement history, and review of data request responses regarding final retirements and descriptions of assets in specific accounts.

Staff Case D

While Staff recommends the Commission authorize GMO's depreciation rates identified in Staff Case A discussed above, Staff has developed Staff "Case D" depreciation rates. Staff "Case D" used a negative 12% terminal net salvage for the Life Span analysis of the Steam production accounts as a comparison with Staff "Case C" which used 0% terminal net salvage. Otherwise Staff Case D is identical to Staff Case C. The negative 12% terminal net salvage is consistent with the observed history of cost of removal for KCPL, MPS and L&P, see discussion below. For MPS and L&P the increase in depreciation expense for the negative 12% net salvage is shown in Appendix 9, Schedule AR-MPS-3 and AR-L&P-3, as approximately $500,000 and $1,000,000 respectively.

E. Treatment of Steam Production Plant Accounts

Modeling for depreciation analysis studies the mortality characteristics of plant in service. The mortality characteristics for various plant accounts may differ. Selection for treatment as Living accounts versus Dying accounts addresses one of the main differences in observed mortality characteristics. The Mass Property depreciation model is applied to plant accounts where each addition to the account as years go by (each vintage) is expected to have the same average service life - living accounts. The Life Span depreciation model is applied to plant accounts where each addition to the account as years go by (each vintage) is *not* expected to have the same average service life - dying accounts.

For electric plant equipment such as transmission or distribution systems, and power generation fleets, the Mass Property model is appropriate since all vintages are assumed to have the same average service life. With these types of accounts, it is assumed that all retirements will be recorded and retired property is expected to be replaced by comparable property, with or without improvements in technology. Treatment as a living account assumes the account as a whole will continue to live indefinitely[60]. If a specific termination date where all property of all

[60] The FERC and Commission rules prescribe accounts in a Uniform System of Accounts. The USOA prescribes that assets are accounted for by function. The FERC and Commission definition of DEPRECIATION states "...from causes which are <u>known</u> to be in current operation..." not implied, thought, believed, conjectured, assumed, etc. The Commission has usually prescribed depreciation rates only by the main USOA functional accounts. It is Staffs opinion that the great majority of electricity produced in Missouri in the foreseeable future will continue to be generated by the spinning of a shaft (rotor & armature), powered by flowing water, steam, or combustion gases. Replacement of these facilities with wind turbines, solar, fuel cells, or capturing solar winds is not within the current depreciable lives of these facilities. Consequently the USOA functional accounts remain relevant as living accounts. While it is known that generation units will retire, it is also known from the Company's history that these facilities typically evolve piecemeal by replacement with similar functional units.

vintages will be retired at the same time becomes known, the treatment of the account should shift to a dying account.

For dying accounts, such as a large **single** electric generating plant or unit, the Life Span model is appropriate since a specific termination date where all property of all vintages will be retired is known or can be accurately estimated. Recent additions and replacements (recent vintages) will have shorter average service lives than the original installed vintage property which survived over the whole life span. Simple modeling of interim retirements for a single large production unit will not give a representative average service life estimate. This introduces two types of survivor curves used to determine the ASL (average service life).

The curves generated for these two methods are from two different historical data sets and are not interchangeable.

Staff's recommended Case A treats Steam production plant and other production plant as generation fleets for MPS and L&P. The retirement history includes sufficient final retirements from units previously removed from service to represent a fleet of production units. These final retirements represent the retirement of short-lived property which occurs when a production unit is shutdown. It is up to the discretion of the analyst to determine which is the better representation of the future, the future projected retirement dates for individual units (dying account - life span), or the final retirement history of previous production units (living account - mass property). Staff's recommended Case A treats production plant as generation fleets using the living account Mass Property method.

1. Mass Property Type Survivor Curves

The average service life (ASL) for an account is represented by the area under a survivor curve. A survivor curve is constructed which shows the percent of the account dollars which survive past a given age. The survivor (Iowa) curve used in the determination of the ASL is dependent on the model chosen. The Iowa curve derived for use with the Mass Property method is derived from analysis of a historical data set which includes all non-reimbursed retirements, including all final retirements from any production units which have been removed from service. See Figure 1. The entire area under the curve represents the average service life. The survivor curve in Figure 1 has an Iowa curve designator of 47-R2. For the Mass Property type curve this designator indicates the average service life for this model is 47 years. Figure 1 is representative of a typical steam production boilers account for a fleet of production units where the retirement history studied includes all retirements from individual units which have been removed from service. Staff Case A used this method.

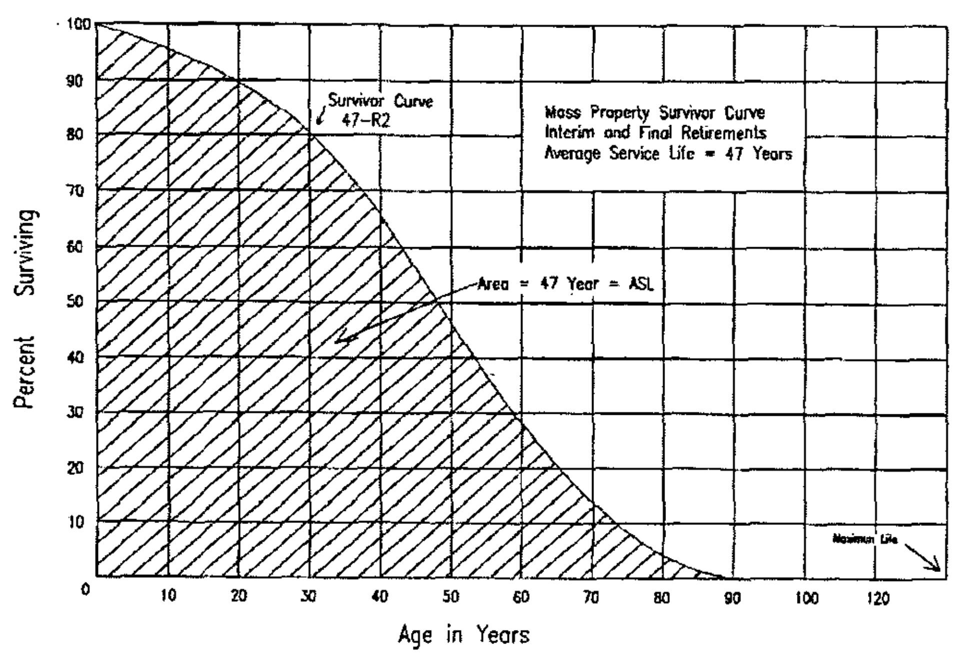


Figure 1 Mass Property Type Survivor Curve

The Companies have provided sufficient final retirement history including terminal retirements to allow reasonable estimation of average service lives for the Company's steam production accounts.[61]

Staff does not generally have a means of accurately predicting a retirement date and conducting life span analysis on each production unit, unless there is a specific issue with that unit. Staff is not aware of any specific issues for MPS or L&P where Staff has reason to assign a specific retirement date. The Commission and Commission Staff have assigned depreciation rates in the past and continue to recommend the assignment of depreciation rates to a fleet of similar production units.[62]

2. Life Span Type Survivor Curve

The Iowa curve derived for use with the Life Span method is from analysis of a historical data set consisting of only the interim retirements. See Figure 2. Note the survivor curve in Figure 2 has an Iowa curve designator of 57-R1. For the Life Span method this 57-R1 curve designation does **not** indicate the average service life. Final retirements are represented in Figure 2 with the vertical line drawn at the retirement or life span date. The area under the curve to the left of the life span date represents the average service life. In this figure the average service life is 47 years, the same as shown in Figure 1. The survivor curve by itself in Figure 2 is representative of interim retirements for a typical steam production boilers account. For a specific steam production unit the final retirements are represented by the truncation of the curve at the life span. The Company proposal used this method for each production unit. Both Figure 1 and Figure 2 show the same average service life of 47 years because, for this example,

[61] Final retirement descriptions provided by the Companies were used to construct representative final retirement entries in the Company-provided historical data file.
[62] Typically all production units have main accounts (ie 311, 314, 322, 344) ordered at the same depreciation rate.

the life span for Figure 2 was specifically chosen at 60 years to produce a 47 year average service life.[63]

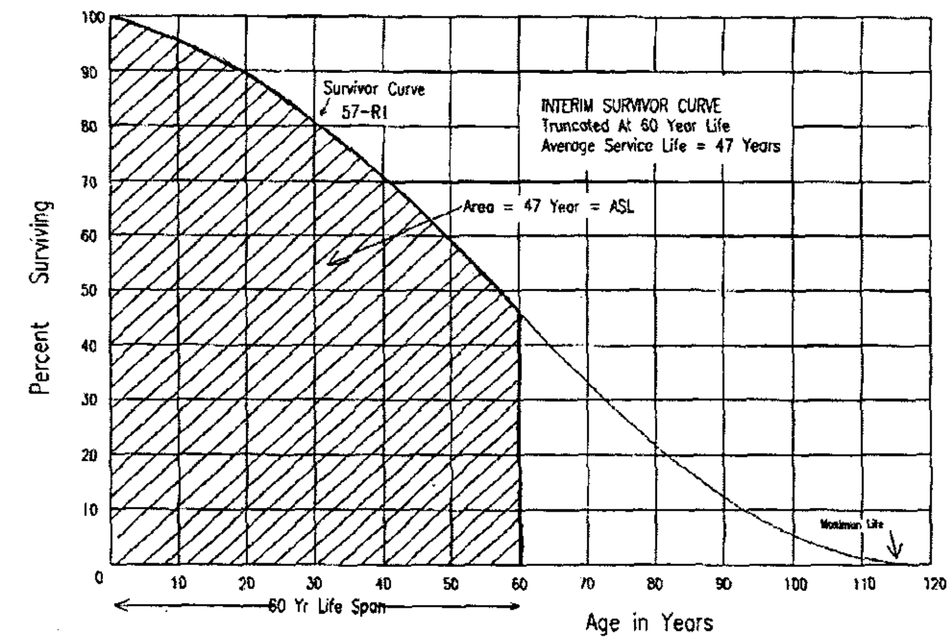


Figure 2 Life Span Type Survivor Curve

[63] **Life Span Property Depreciation Rate Equation:**
The depreciation rate equation for Life Span property should be viewed as having four components, 1) interim retirements, 2) final retirements, 3) interim net salvage, and 4) final net salvage.

The Life Span Depreciation Rate Equation::

$$\text{Rate \%} = \frac{100}{\text{ASLs}} - \frac{\text{Interim Net Salvage \%}}{\text{ASLs}} - \frac{\text{Terminal Net Salvage \%}}{\text{ASLs}}$$

ASLs = average service life in years, from *interim* survivor curve truncated at life span.
Final retirements are specifically identified and removed from the depreciation analysis.

Net Salvage = gross salvage - cost of removal

$$\text{Interim Net Salvage \%} = \frac{\text{net salvage \$}}{\text{Interim Retirement \$}} * 100 * (1 - \text{fraction surviving at life span})$$

The term (1 – fraction surviving at life span) simply corrects this depreciation rate component to represent only the net salvage portion of current plant in service which is expected to retire as interim retirements.

$$\text{Terminal Net Salvage \%} = \frac{\text{terminal net salvage \$}}{\text{Terminal Retirement \$}} * 100$$

For Terminal Net Salvage there is no correction for fraction surviving because at the terminal retirement date it is the current plant which is expected to survive plus the interim additions which are also retired.

F. Treatment of Combustion Turbine Accounts

Staff recommends depreciation analysis treating the Other Production Plant accounts containing predominantly combustion turbine generators and associated facility equipment as a living fleet, using the mass property method. Prior rate case treatment for KCPL and all other recent electric company rates cases in Missouri have depreciation rates set for combustion turbine accounts using the Mass Property method.[64] Staff does not recommend adoption of the Company's (MPS or L&P) request to separately account for each combustion turbine and forecast retirement dates for each combustion turbine.

Mass Property treatment of all combustion turbine production units at all the Company facilities as one large continuous production system is an appropriate representation of the retirement and cost of removal which occurs. Even if one whole combustion turbine unit is replaced, much of the auxiliary and other site support equipment is expected to continue in use to provide service. Assuming the retirement activity is properly recorded, these retirements will be captured by using a living account mass property depreciation analysis.

G. General Accounts Left at Prior Ordered Depreciation Rates for Direct Testimony

During Staff's review of the General accounts which the Company proposed switching to an Amortization or Square Curve method, Staff was unable to reconcile differences found between the Company provided historical data and prior case account balances in audit Staff work papers. The accounts involved are accounts 391, 391.01, 391.02, 393, 394, 395, 397, and 398. An example is L&P account 393 (stores Equipment). Staff shows a June 2010 plant balance of $97,441 with a depreciation reserve of $103,727, which indicates this account is over

[64] This is consistent with the Commission's Report and Order In AmerenMissouri's Case No. ER-2010-0036.

accrued by approximately $6,000. The Company proposal claims L&P account 393 has $23,958 in unrecovered deprecation and an additional $117,989 left to depreciate. This raised questions regarding recent corporate office moves and retirements associated with the acquisition, and the possible effect on any depreciation analysis which used this historical data.

At the time of this direct testimony, Staff recommends keeping the depreciation rates for these accounts at the prior case ordered depreciation rates, not switching to an Amortization Method, and not recommending revised rates. For ECORP, this includes account 390 (Structures and Improvements).

H. Whole Life and Remaining Life

Whole Life depreciation rates may be viewed as the current rate of consumption of plant in service, with no correction in the assigned depreciation rate to adjust for any over or under accrued depreciation reserves. The current ordered depreciation rates, Staff Cases A, and Staff Case B use the Whole Life method of depreciation rate calculation. When Whole Life rates are used, an additional depreciation amortization may be assigned to correct reserve imbalances. For Staff recommended Case A, the assigned amortization for each account shown in AR-MPS-1 and AR L&P-1 is to correct for over or under accrued accumulated reserves.

Remaining Life depreciation rates may be viewed as Whole Life rates that have been modified to account for over or under accrued depreciation reserves. This is accomplished by calculating the total depreciation accruals needed over the expected remaining life of the current plant in service, and dividing by the number of years remaining. Staff Case C and Staff Case D used remaining life rates to compute depreciation accruals.

Staff recommends the use of Whole Life depreciation rates for MPS, L&P and ECORP for the following reasons:

1. Whole Life rates show the current consumption of capital and provide a direct comparison for review with prior rate case or other company depreciation rates,

2. Whole life rates provide a more consistent depreciation accrual in accounts where large changes in balances may occur from additions and retirements between rates cases that review depreciation.

3. Amortization assigned in conjunction with Whole Life rates allow setting a fixed time to apply the amortization, and

4. Fixed amortization associated with Whole Life rates do not fluctuate as plant balances change over time.

I. Interim versus Final (Terminal) Retirements and Net Salvage

When using the depreciation method presented in Staff's Case A, the survivor curve in the Mass Property method is projected to zero survivors. There is no distinction between interim and final retirements or net salvage. All retirements and net salvage for the current total installed plant in service is included in the depreciation rate assigned. The mass property type depreciation rate includes the collection of net salvage on 100% of the plant in service, not just what is expected to be retired as interim retirements.

Retired units which still physically exist have ongoing cost of removal and salvage which may continue for up to 20 plus years.[65] These net salvage costs should continue to be recorded and reflected in the depreciation rate analysis for all plant units as a fleet of production units. The representation of true historical cost for production units will not be reflected in the estimation of depreciation rates if only individual in service units are incorporated into the depreciation analysis, with the final retirement and terminal net salvage history ignored.[66]

[65] The Ralph Green Steam units were retired in 1982 and disposed of in 2010, 28 years later.
[66] Typically all production units have main accounts (ie 311, 314, 322, 344) ordered at the same depreciation rate.

In Staff's Cases C and D, Staff treated the steam production plant for MPS and L&P as Life span property, and Staff was able to distinguish between interim and final retirements. Interim retirements result in interim net salvage. Final (or terminal) retirements are associated with the removal or dismantling of the retired unit. For Staff's Case C, terminal net salvage was modeled at zero % to be consistent with the Life Span model the Commission approved in AmerenUE Case No. ER-2010-0036. For Staff Case D, terminal net salvage was modeled at a negative 12% to demonstrate the variation in depreciation expense when including or not including terminal net salvage in the analysis.

For all GPE associated companies and divisions (KCP&L, GMO MPS, and GMO L&P), Staff has knowledge of five steam production facilities where approximately 15 boiler/turbine units have been shut down and removed from service. Four of these five steam production facilities, consisting of 11 of the approximate 15 units, have been dismantled and disposed of. The total amount retired for these four steam production facilities is $33,141,318, with the associated cost of removal and salvage of $4,196,600 and $216,812, respectively. The resultant overall composite terminal net salvage rate from this historical steam production plant data is a negative 12%.

Staff Expert/Witness: Arthur W. Rice

X. Current and Deferred Income Tax

A. Current Income Tax

Staff calculated income tax liability in this case consistent with the methodology used in GMO's last rate case, Case No. ER-2009-0090. The adjustments made by Staff begin by taking adjusted net operating income before taxes and adding to or subtracting from net income various timing differences in order to obtain net taxable income for ratemaking purposes. These "add back" and/or subtraction adjustments are necessary to identify new amounts for the tax deductions that are different from those levels reflected in the income statement as revenues or expenses. The adjustments are the result of various book versus tax timing differences and the effect of such differences under separate tax methods: flow-through versus normalization A tax timing difference occurs when the timing used in reflecting a cost (or revenue) for financial reporting purposes (book purposes) is different than the timing required by the IRS in determining taxable income (tax purposes). Current income tax reflects timing differences consistent with the timing required by the IRS. The tax timing differences used in calculating taxable income for computing current income tax are as follows:

<u>Add Back to Operating Income Before Taxes</u>:

- Book Depreciation Expense
- 50% Meals and Entertainment Disallowance
- Contribution in Aid of Construction
- Advances for Construction

<u>Subtractions from Operating Income:</u>

- Interest Expense – Weighted Cost of Debt X Rate Base
- Tax Straight-Line Depreciation
- Tax Depreciation over Straight Line Tax
- IRS Section 199 Domestic Production Activities

The normalization tax method defers the tax deduction taken for tax purposes for those taxes that are taken as tax deduction for ratemaking purposes.

The flow-through tax method essentially provides for the same tax deduction taken as a deduction for ratemaking purposes as is taken for tax purposes.

The resulting net taxable income for ratemaking is then multiplied by the appropriate federal and state tax rates to obtain the current liability for income taxes. A federal tax rate of 35 percent and a state income tax rate of 6.25 percent were used in calculating MPS and L&P's share of GMO's current income tax liability. This composite tax rate (state and federal combined together) is 38.39%. The difference between the calculated current income tax provision and the per book income tax provision is the current income tax provision adjustment.

B. Straight Line Tax Depreciation

Annualized book depreciation is a result of multiplying the plant investment at June 30, 2010, the end of the update period used by Staff for this proceeding, by the book depreciation rates being recommended by Staff witness Arthur W. Rice of the Engineering and Management Services Department. Straight line tax depreciation represents the tax deduction for book depreciation for a regulated utility for ratemaking purposes.

The IRS allows a regulated utility, like all corporations, to use an accelerated depreciation method in calculating its current income tax liability. However, with regard to a regulated utility, Congress intended for the additional cash flow (lower current income tax), resulting from an accelerated depreciation method, to be retained by the utility. As a result, under IRS rules for a regulated utility, the additional deduction resulting from the use of an accelerated depreciation method cannot be reflected in rates. Ratepayers receive the tax deduction for depreciation expense over the same period used for book accounting purposes.

Staff Expert/Witness: Paul R. Harrison

C. Deferred Income Tax Expense

When a tax timing difference is reflected for ratemaking purposes consistent with the timing used in determining taxable income for current income tax as the result of the Internal Revenue Code (IRC), the timing difference is given "flow-through" treatment.

When a current year timing difference is deferred and recognized for ratemaking purposes consistent with the timing used in calculating pre-tax operating income in the financial statements, then that timing difference is given "normalization" treatment for ratemaking purposes. Deferred income tax expense for a regulated utility reflects the tax impact of "normalizing" tax timing differences for ratemaking purposes. IRS rules for regulated utilities require normalization treatment for the timing difference related to accelerated tax depreciation.

For most utilities, it is necessary to break out a utility's tax depreciation into two separate components: tax straight-line depreciation and excess tax depreciation. Tax straight-line depreciation is different from book straight-line depreciation due to the different tax basis of property allowed under the tax code. Excess tax depreciation differs from straight-line book depreciation due to the higher depreciation rates allowed in the early years of an asset's life under the current tax code. Most tax basis differences were eliminated for assets placed into service after 1986 due to the Tax Reform Act enacted that year.

Staff's standard deferred income tax adjustment consists of three components:

1. IRS Schedule M timing differences: contributions in aid of construction and advances for construction. These amounts are normalized consistent with Staff's calculation in the prior rate case filing;

2. The tax timing difference between tax straight-line depreciation expense and tax depreciation expense: This treatment is consistent with the normalization calculation in the previous rate case filing; and

3. Excess deferred income taxes resulting from the 1986 Tax Reform Act, which created excess deferred tax amounts associated with depreciation timing differences: As such, an amortization has been created to amortize excess deferred taxes created from the change in tax rates back to customers.

Normally a combination of the above three components make up the amounts recorded as deferred income tax expense.

D. Kansas City Earnings Tax

Staff normalized the Kansas City, Missouri earnings tax (KCET) in this rate case. This is included in the revenue requirement calculations for MPS & L&P as Adjustments E-169.1 and

E-176.1, respectively. The amounts were determined as part of the tax calculation for the KCPL rate case, Case No. ER-2009-090 and included in Staff's Accounting Schedule 11, Income Tax calculation. As discussed below, it is Staff's position that a portion of the KCET tax should be allocated to MPS and L&P. The adjustments to normalize and allocate the earnings tax are necessary to properly reflect an amount for the local Kansas City tax in current rates for MPS and L&P. During the review of KCPL costs, Staff discovered when this tax was made part of the tax calculation in KCPL's last rate case, it overstated costs. When the earnings tax was included in the tax calculation on Staff Accounting Schedule 11 and factored up for income taxes, it was creating a significant difference between the amount of earnings taxes actually paid and the level that was determined in the tax calculation. For example, in KCPL's last rate case, Staff included $887,104 for earnings taxes computed as part of the tax when ultimately the Company actually only paid $74,443 for 2009.

The actual earnings tax for KCPL, as determined by the city of Kansas City, is calculated by dividing the amount of gross receipts tax paid to Kansas City, and KCPL's payroll and plant identified within the Kansas City area by the amount of total company gross receipts, payroll and plant. This ratio is then multiplied by KCPL's total company net income to calculate the earnings taxes.

Because the Kansas City earnings taxes are required as a right to conduct business in the city of Kansas City, Staff believes that 25% of the earnings taxes should be allocated to Kansas, MPS and L&P customers. The KCPL corporate office building and a predominate number of KCPL employees are located inside the Kansas City, Missouri area, which result in a higher payment to the city of Kansas City for the earnings tax. As a result of the location of the office building and the number of employees that work out of it, two of the three amounts (payroll and plant) that are used to calculate the ratio that is used to determine the amount of the earnings taxes are increased significantly. Additionally, this ratio is multiplied by KCPL's total company net income (which includes Kansas and GMO net income). This causes the earnings taxes to be significantly higher than if the building and employees were located outside of the Kansas City Area.

In order to ensure a proper allocation of the earnings tax costs to various KCPL affiliates that benefit from KCPL's corporate office function, the costs of the offices located in Kansas City and included in the earnings taxes should be assigned to each of KCPL, MPS, and L&P. Staff recommends that GMO perform a cost study with the goal of determining a reasonable and proper allocation of the earnings tax.

Because the corporate office activities such as management oversight and accounting functions benefits all KCPL, MPS, L&P, it is appropriate to allocate a portion of the earnings taxes to each, just as it is proper to allocate other corporate office costs, like salaries and office rents. Staff believes that 25 percent is an appropriate allocation, and recommends that KCPL conduct an allocation study in the future.

Staff Expert/Witness: Paul R. Harrison

E. Accumulated Deferred Income Tax and Amortization

MPS's and L&P's deferred income tax reserve represents, in effect, a prepayment of income taxes by MPS's and L&P's customers. As an example, because MPS and L&P are allowed to deduct depreciation expense on an accelerated basis for income tax purposes, depreciation expense used for income taxes is significantly higher than depreciation expense used for financial reporting (book purposes) and for ratemaking purposes. This results in what is referred to as a book-tax timing difference, and creates a deferral, or future liability of income taxes. The net credit balance in the deferred tax reserve represents a source of cost-free funds to MPS and L&P. Therefore, MPS's and L&P's rate base is reduced by the deferred tax reserve balance to avoid having customers pay a return on funds that are provided cost-free to the Company. Generally, deferred income taxes associated with all book-tax timing differences which are created through the ratemaking process should be reflected in rate base.

The 1986 Tax Reform Act reduced the federal tax rate for corporations from 46% to 34%. As a result, all deferred taxes, previously reflected in rates, based upon an assumed 46% tax rate, were overstated. The IRS allowed a regulated utility to flow back to ratepayers (amortize) the excess deferred taxes over the approximate depreciable book life of the property. Staff's income tax calculation, for MPS and L&P in this current case, reflects an amortization of excess deferred taxes resulting from the reduction in the federal tax rate in 1986.

Prior to the 1986 Tax Reform Act, a utility received a permanent tax credit for investing in new capital additions. For ratemaking purposes, the IRS allowed the utility to amortize (flow back to ratepayers) the investment tax credit over the approximate depreciable book life of the related property.

Staff Expert/Witness: Paul R. Harrison

F. MPS Deferred Income Taxes Accounting Authority Order (AAO)

Staff has also included the accumulated deferred taxes related to the 1990 and 1992 Accounting Authority Orders (AAO) approved by the Missouri Public Service Commission in Case Nos. EO-91-358 and EO-91-360 for MPS in Staff Accounting Schedule, Rate Base Schedule 2. These AAO's deferred the depreciation expenses and carrying costs associated with the life extension construction and coal conversion project at the Sibley Generating Station.

Staff Expert/Witness: Paul R. Harrison

G. Iatan No. 2 Advanced Coal Credit

In April 2008, KCPL was notified that its application filed in 2007 for $125.0 million in advanced coal investment tax credits (ITC) was approved by the IRS. The credit is based on the amount of expenses incurred on the construction of Iatan 2. Additionally, in order to meet the advanced clean coal standards and avoid forfeiture and/or the recapture of tax credits in the future, KCPL must meet or exceed certain environmental performance standards for at least five years once the plant is placed in service.

In February 2009, KCPL was served a notice to arbitrate by Empire District Electric Company (Empire), Kansas Electric Cooperative, Inc. (KEPCO) and Missouri Joint Municipal Electric Utility Commission (MJMEUC), joint owners of Iatan 2. The joint owners asserted that they are entitled to receive proportionate shares (or the monetary equivalent) of approximately $125.0 million of qualifying advance coal project credit for Iatan 2. As independent entities, the joint owners are taxed separately and the joint owners do not dispute that they did not, in fact, apply for the credits themselves. Notwithstanding this, the joint owners contend that they should receive proportional shares of the credit. This matter was heard by an arbitration panel in November 2009.

On December 30, 2009, the arbitration panel issued its order denying the KEPCO and MJMEUC claims but ordering KCPL and Empire to jointly seek a reallocation of the tax credit from the IRS seeking to give Empire its representative percentage of the total tax credit, worth approximately $17.7 million for its twelve percent ownership. The order further specifies that if the IRS denies the parties' reallocation request or if Empire is allocated less than its proportionate share of the tax credits, KCPL will be responsible for paying Empire the full value of its representative percentage of the tax credits (less the amount of tax credits, if any, Empire ultimately receives) in cash. KCPL has recorded a $17.7 million liability in other current liabilities for this matter.

GMO owns eighteen percent of the Iatan 2 power plant. Staff asserts that since GMO owns eighteen percent of Iatan 2, it is entitled to receive a proportionate share (or monetary equivalent) of the approximately $125 million of qualifying advance coal project credit for Iatan 2. Even though MPS and L&P are not actually taxed separately for income tax purposes, it is necessary to determine income tax expense for MPS and L&P separately for rate making purposes because they maintain separate rate structures. For rate making purposes, MPS and L&P's cost of service is based upon its own rate base, revenues, expenses and income tax liability. Therefore, Staff has made an adjustment to allocate eighteen percent of the advanced coal credit that KCPL received from the IRS to GMO (MPS and L&P). This equates to approximately $26.5 million.

Because Iatan 2 is allocated between MPS and L&P, it is necessary to allocate an appropriate amount of the $26.5 million for the advance coal credit to each. Staff has allocated MPS and L&P's share of the advance coal credit based on the allocation of Iatan 2 costs between MPS and L&P, 65.4 percent and 34.6 percent, respectively.

Staff Expert: Paul R. Harrison

XI. Fuel Adjustment Clause

A. Recommendation

Staff recommends that the Commission approve, with modifications, the continuation of GMO's Fuel Adjustment Clause ("FAC"). Staff has reviewed the minimum filing requirements documents the Company provided in Schedules TMR2010-1, TMR2010-2, TMR2010-3, TMR2010-4 and TMR2010-5 attached to the pre-filed Direct Testimony of Company witness

Tim M. Rush and believes that with these documents the Company has complied with the minimum filing requirements contained in 4 CSR 240-3.161(3) to inform the public of the Company's requested continuation of and changes to its FAC in this case.

At this time Staff does not have an estimate for the Base Energy Cost for the FAC in this case, but will include its estimate of the appropriate Base Energy Cost when it files its Class Cost-of-Service and Rate Design testimony on December 1, 2010. Staff recommends the Base Energy Cost in the FAC be set equal to the Base Energy Cost in the test year true-up total revenue requirement for this case.

Staff recommends that the Company's FAC tariff be modified to: 1) change the sharing mechanism from 95%/5% to 75%/25% to provide the Company with a more appropriate incentive to keep its fuel and purchased power costs down, 2) include language that the Base Energy Cost in the FAC be set equal to the Base Energy Cost in the test year total revenue requirement in the rate case to assure that the Company does not benefit or is not penalized as a result of the two Base Energy Costs being different in the rate case, and 3) delete two FERC accounts now included in the definition of Purchased Power Costs, since these FERC accounts are for transmission expenses and are not consistent with the definition of fuel and purchased power costs in 4 CSR 240-20.090(1)(B).

Finally, Staff recommends that the Commission order the Company to continue to provide or make available information and documents to assist Staff during its performance of FAC tariff, prudence and true-up reviews.

B. Summary of Current FAC

The Commission first authorized a FAC for GMO in its Report and Order in KCP&L Greater Missouri Operations Company's 2007 rate case (File No. ER-2007-0004) for GMO's then Aquila Networks-MPS (MPS) and Aquila Networks-L&P (L&P) divisions, with the original FAC tariff sheets having an effective date of July 5, 2007. In the subsequent GMO rate case, File No. ER-2009-0090, the Commission authorized continuation with modifications of the GMO FAC. The primary features of GMO's present FAC (tariff sheet numbers 124 through 127.5) include:

- Two 6-month accumulation periods: June through November and December through May;
- Two 12-month recovery periods: March through February and September through August;
- Separate Cost Adjustment Factors ("CAF") for MPS and for L&P;
- Two CAF filings annually not later than January 1 and July 1;
- A 95%/5% sharing mechanism;
- CAF rates for individual service classifications are adjusted for the two GMO service voltage levels, rounded to the nearest $0.0001, and charged on each applicable kWh billed; and
- True-up of any over- or under-recovery of revenues following each recovery period with true-up amount being included in determination of CAFs for a subsequent recovery period.

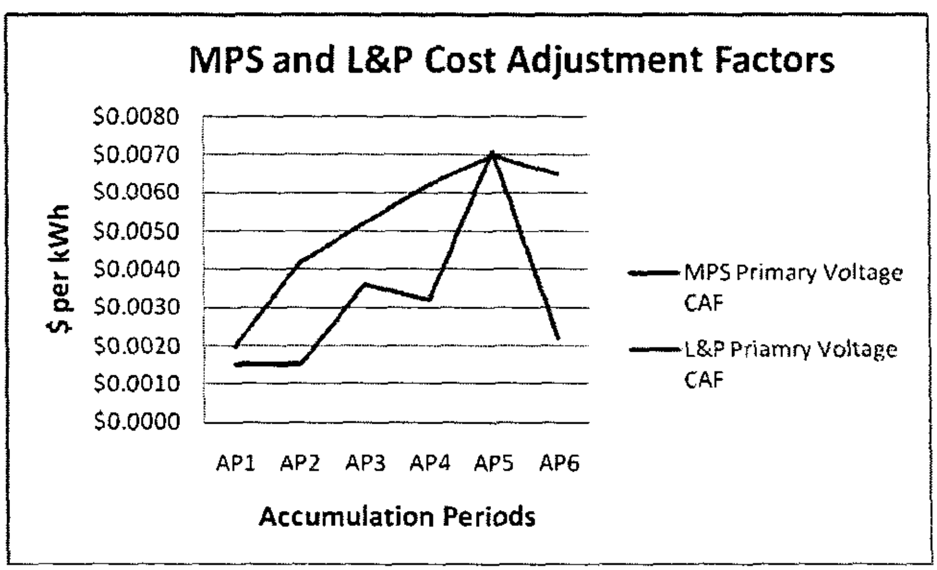
GMO has made six CAF filings (Case/File Nos. EO-2008-0216, EO-2008-0415, EO-2009-0254, EO-2010-0002, EO-2010-0191, and ER-2010-0385), and the resulting changes to the GMO CAFs ordered by the Commission are summarized in the **Continuation of FAC** section of this report. The MPS and L&P Base Energy Cost per kWh rates were originally set in GMO's 2007 rate case (Case No. ER-2007-0004) and were changed as a result of the settlement of GMO's 2009 rate case (Case No. ER-2009-0090) from $0.02538 per kWh to $0.02348 per kWh for MPS and from $0.01799 per kWh to $0.01642 per kWh for L&P.

Staff has filed two prudence review reports concerning its review of the costs of the Company's FAC and found no evidence of imprudent decisions by the Company's management related to procurement of fuel for generation, purchased power and off-system sales. Staff's prudence review reports are in Case Nos. EO-2009-0115 and EO-2010-0167, and cover the periods June 1, 2007 through May 31, 2008 and June 1, 2008 through May 31, 2009, respectively.

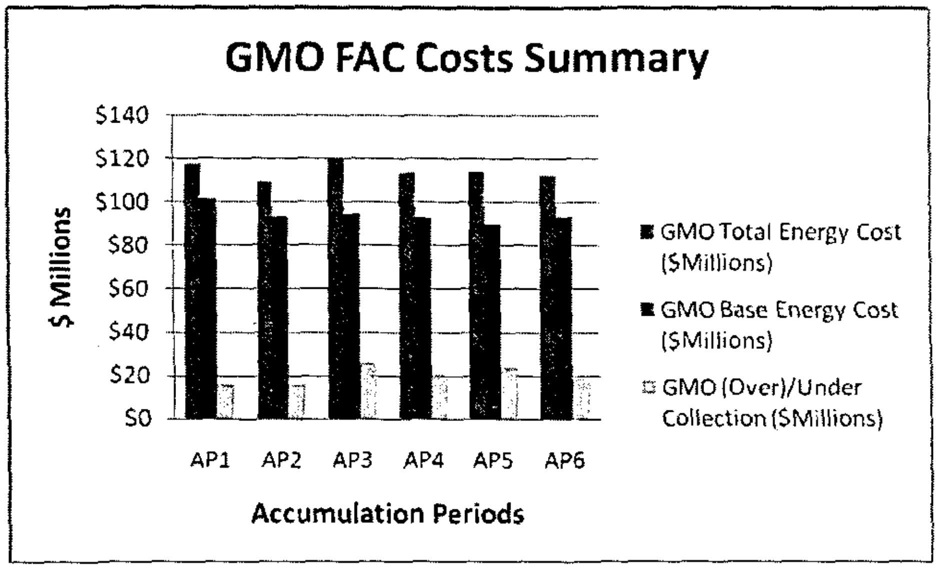
C. Continuation of FAC

Staff recommends that the Commission approve, with modifications, the continuation of GMO's FAC.

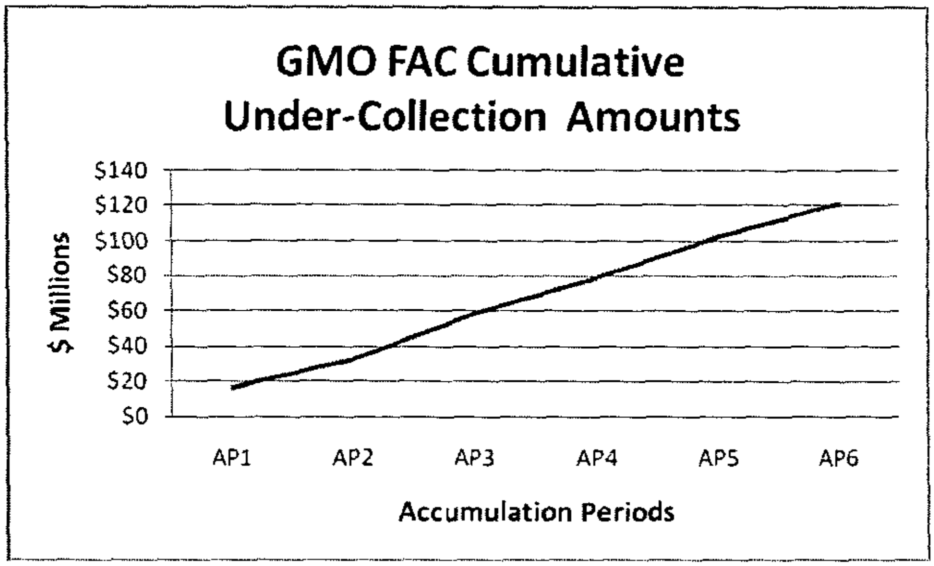
The Company has filed for and received approval of changes to its CAF's for six completed accumulation periods (AP1, AP2, AP3, AP4, AP5 and AP6). The primary voltage CAFs of MPS and L&P for each accumulation period are reflected in the following chart:

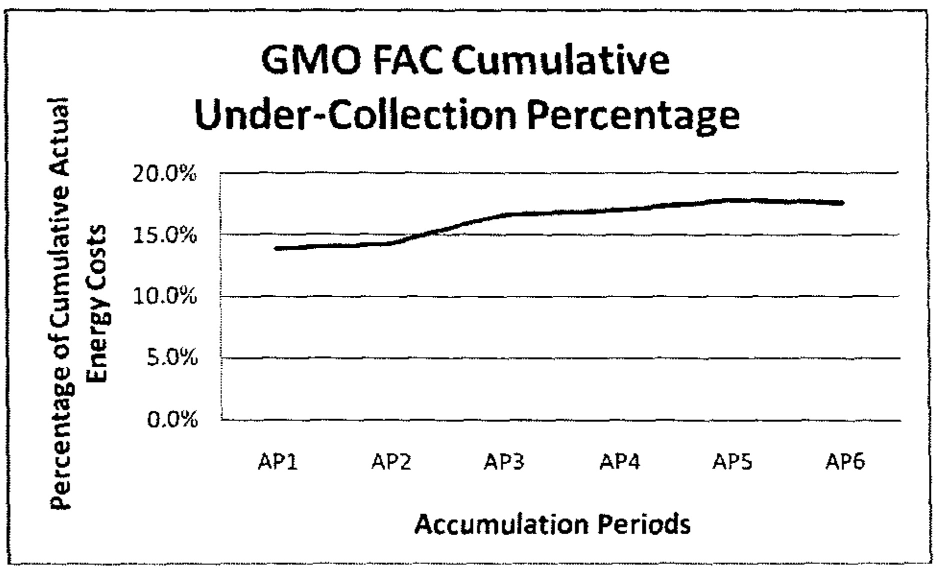


The Company's total actual energy costs have exceeded the base energy costs collected through customers' bills for GMO in each of the six completed accumulation periods. The following chart illustrates the GMO total actual energy costs, the GMO base energy costs as estimated using the Base Energy Cost per kWh rates in the FAC tariff, and the GMO (over)/under collection of actual energy costs for each of the six accumulation periods:



The following two charts illustrate the following information for the first six accumulation periods: 1) cumulative amount of the difference between actual energy costs and the base energy costs as calculated using the Base Energy Cost rates in GMO's FAC tariff sheets, and 2) percentage of cumulative under-collection of the difference between actual energy costs and the base energy costs as calculated using the Base Energy Cost rates in GMO's FAC tariff sheets:





From the above information Staff observes that the FAC under-collected amount over three years of $121 million (18 percent of total actual energy costs of $557 million) is a significant amount for GMO. Staff's analysis and discussion in the **Sharing Mechanism of FAC** section which follows suggests that without the FAC GMO would have lost approximately half of its test year net income before taxes[67] (NIBT) due to under-collection of fuel and purchased power costs less off-system revenue during the timeframe of the FAC's first six accumulation periods.

D. Sharing Mechanism of FAC

GMO's FAC has been in effect for over three years which provides Staff with sufficient information that is necessary to evaluate the impact of the current 95%/5% GMO FAC sharing mechanism over the first six accumulation periods and to evaluate several other selected sharing mechanisms for the impact they would have had on the Company's test year net income before taxes. Given its analysis, Staff proposes changing the current 95%/5% FAC sharing mechanism to a 75%/25% FAC sharing mechanism. The Commission has stated the objective of the FAC sharing mechanism is to provide an incentive for the Company to "keep its fuel and purchased power costs down." To do so requires incenting the utility to develop and manage an effective energy procurement process which minimizes energy costs while managing risk of loss of energy supply. The Commission first expressed its view in its Report and Order in Case No. ER-2007-0004 where it first established the current 95%/5% sharing mechanism when it stated on page 54:

> The Commission also finds after-the-fact prudence reviews alone are insufficient to assure Aquila will continue to take reasonable steps to keep its fuel and purchased power costs down, and the easiest way to ensure a utility retains the incentive to keep fuel and purchased power costs down is to not allow a 100% pass through of those costs.

[67] Net income before taxes in Staff Accounting Schedules for the MPS and the L&P test year income statements filed on January 18, 2007 in File No. ER-2007-0004 ($71,817,796 on line 103 Accounting Schedule 9-3 for MPS and $9,263,787 on line 106 of Accounting Schedule 9-3 for L&P) and filed on February 13, 2009 in File No. ER-2009-0090 ($90,051,142 on line 186 of Accounting Schedule 9 (page 5 of 6) for MPS and $6,307,908 on line 191 of Accounting Schedule 9 (page 5 of 6) for L&P).