EXECUTIVE SUMMARY

Oak Creek, CO
2012 Electric Financial Plan, Cost of Service
And Rate Design Study Update

SECTION I. – EXECUTIVE SUMMARY

The City of Oak Creek concerned about continued load growth, planned system facilities improvements, and necessary increases in labor and general operating expenses requested that NMPP Energy conduct a Financial Plan, Cost-of-Service, and Rate Design Study, (COS/RDS). This report summarizes the findings and recommendations resulting from the development of a five-year Financial Planning Model. Following direction from Oak Creek Staff and after presentation of preliminary results to the City Council, the COS Study and Rate Design will be completed and recommendations forwarded for consideration.

This report discusses the findings and recommendations resulting from an electric financial plan. This financial projection for the utility indicates no need for rate increase for the next 3 years. However, in future years, to maintain net income and cash reserves at system financial targets future 3.0% increases may be necessary. New rates could be designed to bring the classes of customers closer to their cost of service using a rate design guideline of plus or minus 2.0% from the system average increase. For example, with a 0.0% system increase some classes that are below COS could receive 2.0% more (2.0%) while other classes above cost of service could receive 2.0% less (-2.0%). Following direction from the Staff and the City Council, the rate design will be completed and the Final Report, with recommendations for consideration, will be produced.

The study includes in the Financial Planning Model assumptions for power supply costs, capital construction, operations and maintenance costs, and earnings on reserves. The Model indicates that Oak Creek presently has sufficient cash reserves, but due to projected increases in purchased power costs, possible debt service requirements for future capital projects, and normal operating business operations, these reserves will diminish in the future serving to stabilize rates for consumers. The electric utility may require increases in 2016 to maintain net income targets and keep cash reserves above minimum floor amounts.

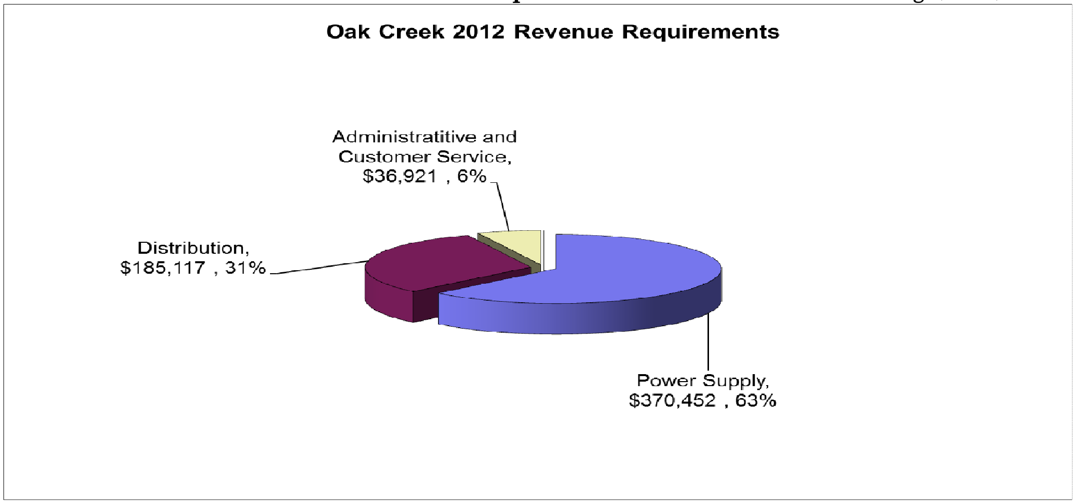
Below is Chart 1 showing the $592,490 total revenue requirements used in the Cost of Service Study, broken down by specific cost functions that are allocated to rate classes. Purchased Power costs together are $370,452, the largest component of total revenue requirements at 63% of the total. Plant Operations and Distribution costs are $118,117 or 31% and Customer Accounts, and Administrative and General costs, is $36,921, or 6% of total revenue requirements. These values include depreciation, miscellaneous revenue, and net return on investment values distributed based on allocation factors.

NMPP • MEAN • NPGA • ACE

August 3, 2012

NMPP Energy ■ 1111 O Street - Suite 200 ■ Lincoln, NE 68508
■ Phone: 402.474.4759 ■ Fax: 402.474.0473
P.O. Box 95124 ■ Lincoln, NE 68509 ■ www.nmppenergy.org

Chart 1 – Oak Creek Cost-of-Service Revenue Requirements for Fiscal Year Ending (FYE) 2012



Oak Creek's purchased power costs are budgeted to increase by 6.0% in FYE 2012. Western Area Power Administration from the Loveland Area Project Region (Western-LAP) had no rate increase in 2012; however the Municipal Energy Agency of Nebraska (MEAN) wholesale increase was 7.35% effective April 1, 2012. Annual projections for future years are 5% for MEAN, 3.0% for Western Support Energy, and 4.0% for Western Power and Transmission. MEAN Wind rates were not increased in 2012 but are assumed to increase annually about $2 per Megawatt-hour (MWh) for 2013 and beyond (~4.0%). The sum of these power and transmission cost are shown in line 6 of Tables A and C later in the report.

In addition to changes in power costs the study incorporates increases in loads and operating costs. Individual escalators for labor, supplies, capital construction, long-term borrowing and earnings on reserves are used to determine the revenue requirements for the test year and for each year to FYE 2017.

PROJECTED REVENUE REQUIREMENTS

A critical aspect of a cost of service analysis is determination of the utility revenue requirements. The revenue requirement for full cost-of-service (COS) rate recovery includes a 5.0% return on distribution and power system investments less accumulated depreciation expenses. We typically recommend a net income target (line 16) between 4.0% and 9.0% return on investments (ROI) in depreciated utility plant. The current rates are estimated to produce 18.0% ROI in 2012 (line 18), and with no rate increase in the next five years the ROI drops to 0.5% in 2017. Table A shows FYE 2011 actual and 2012-2017 projected statement of income and expenses and total revenue requirements of $592,490, line 19. For FYE December 2012, existing rates are estimated to derive $653,308 in revenue (line 2) resulting in $84,173 in net operating income (line 16) which takes cash balance to $572,014 (line 33). The projections are based on the City's Budget projections and adjustments to 2013 revenues that include billing city building under the applicable general service rate.

EXECUTIVE SUMMARY

Oak Creek, CO
2012 Electric Financial Plan, Cost of Service
And Rate Design Study Update

TABLE A PRO-FORMA OPERATING STATEMENTS WITHOUT RATE ADJUSTMENTS

	FYE December		2011	2012	2013	2014	2015	2016	2017
a	Sales Growth Base Load		3.4%	-2.3%	0.5%	0.5%	0.5%	0.5%	0.5%
b	Administration Inflation		3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%
c	General Inflation		3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%
e	Purchase Power Adjustments		1.1%	5.3%	4.0%	4.1%	4.1%	4.1%	4.1%
f	**Rate Adjustments**		**3.4%**	**3.4%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**	**0.0%**
	Effective date		**Jul. 2011**	**Jan. 2012**	**Jan. 2013**	**Jan. 2014**	**Jan. 2015**	**Jan. 2016**	**Jan. 2017**
1	**Revenues**								
2	Retail Sales		$ 668,430	$ 653,308	$ 693,759	$ 697,228	$ 700,714	$ 704,218	$ 707,739
3	Other Operating Rev		26,324	24,295	24,416	24,539	24,661	24,785	24,908
4	**Total Revenues**		**$ 694,754**	**$ 677,603**	**$ 718,176**	**$ 721,767**	**$ 725,375**	**$ 729,002**	**$ 732,647**
5	**Expenses**								
6	Power Purchased		$ 335,640	$ 340,905	$ 356,362	$ 372,820	$ 390,079	$ 408,194	$ 427,206
7	Capacity Payments		(27,531)	(30,808)	(30,808)	(30,808)	(30,808)	(30,808)	(30,808)
8	Production Power		19,563	17,230	17,747	18,279	18,828	19,393	19,974
9	Operation and Maintenance		30,004	35,800	36,874	37,980	39,120	40,293	41,502
10	Distribution		29,774	30,500	31,415	32,357	33,328	34,328	35,358
11	Adm. and Gen.		119,710	120,460	124,074	127,796	131,630	135,579	139,646
12	City Mgtm Services	10%			69,376	69,723	70,071	70,422	70,774
13	**Total O&M**		**$ 507,160**	**$ 514,087**	**$ 535,664**	**$ 558,425**	**$ 582,177**	**$ 606,978**	**$ 632,878**
14	Depreciation		$ 76,343	$ 79,343	$ 82,433	$ 85,616	$ 88,894	$ 92,270	$ 95,748
15	**Total Electric Expense**		**$ 583,503**	**$ 593,430**	**$ 618,097**	**$ 644,041**	**$ 671,070**	**$ 699,249**	**$ 728,626**
16	**Net Operating Income**		**$ 111,251**	**$ 84,173**	**$ 100,079**	**$ 77,726**	**$ 54,305**	**$ 29,753**	**$ 4,021**
17	**Net Income Target % of UPIS**	5.0%	**$ 19,793**	**$ 23,355**	**$ 27,024**	**$ 30,804**	**$ 34,697**	**$ 38,706**	**$ 42,836**
18	**Net Income Actual % of UPIS**		**28.1%**	**18.0%**	**18.5%**	**12.6%**	**7.8%**	**3.8%**	**0.5%**
19	COS Revenue Requirement			**$ 592,490**					
20	**Other Revenues & Expenses**								
21	Interest on existing LT Debt		(13,345)	$ (12,145)	$ (10,761)	$ (9,407)	$ (7,973)	$ (6,454)	$ (4,845)
22	**Total Profit / Loss**		**$ 97,906**	**$ 72,028**	**$ 89,318**	**$ 68,319**	**$ 46,332**	**$ 23,300**	**$ (824)**
23	**Cash Inflows**								
24	Net Income		$ 97,906	$ 72,028	$ 89,318	$ 68,319	$ 46,332	$ 23,300	$ (824)
25	Depreciation Expense		$ 76,343	$ 79,343	$ 82,433	$ 85,616	$ 88,894	$ 92,270	$ 95,748
26	Cash Inflows		**$ 174,249**	**$ 151,371**	**$ 171,751**	**$ 153,935**	**$ 135,226**	**$ 115,570**	**$ 94,924**
27	**Cash Outflows**								
28	Capital Improvements & CWIP		75,000	77,250	79,568	81,955	84,413	86,946	89,554
29	Principal on Existing Debt		20,355	$ 21,560	$ 22,939	$ 24,293	$ 25,727	$ 27,246	$ 28,855
30	Principal on New Debt								
31	**Cash Outflows**		**$ 95,355**	**$ 98,810**	**$ 102,506**	**$ 106,248**	**$ 110,140**	**$ 114,192**	**$ 118,409**
32	Change in Cash		**$ 78,894**	**$ 52,561**	**$ 69,244**	**$ 47,687**	**$ 25,086**	**$ 1,378**	**$ (23,485)**
33	**Cash Balance**		**$ 519,453**	**$ 572,014**	**$ 641,258**	**$ 688,945**	**$ 714,031**	**$ 715,409**	**$ 691,925**
34	**Cash Balance Target**		**251,612**	**256,304**	**264,335**	**272,342**	**280,264**	**288,105**	**295,867**

NMPP • MEAN • NPGA • ACE

August 3, 2012

NMPP Energy ■ 1111 O Street - Suite 200 ■ Lincoln, NE 68508
■ Phone: 402.474.4759 ■ Fax: 402.474.0473
P.O. Box 95124 ■ Lincoln, NE 68509 ■ www.nmppenergy.org

EXECUTIVE SUMMARY

Oak Creek, CO
2012 Electric Financial Plan, Cost of Service
And Rate Design Study Update

PROJECTED CASH FLOW

Table A above shows capital improvements and Construction-Work-In-Progress (CWIP) in line 28, and is budgeted at $77,250 for 2012, and is projected to grow at an inflationary rate for future years. For 2012, the $572,014 Cash Balance (line 33) is above the minimum reserve recommendation of $256,304 (line 34). The minimum cash reserve is based on a recommended policy illustrated in Table B below.

TABLE B – MINIMUM CASH RESERVE POLICY

	Cash Reserve Policy			2012
1	O&M Expenses FYE 2012	514,087	25%	128,522
2	Historic Utility Plant in Service (Gross Plant	1,912,477	1%	19,125
3	Deposits	0	100%	-
4	Debt Service	33,705	100%	33,705
5	Current Year Capital Improvements less Borrowings	77,250	15%	11,588
6	Five Year Capital Improvements less Borrowings	422,435	15%	63,365
7	**Minimum Reserve Target**			**256,304**

CASH RESERVE POLICY DISCUSSION

A minimum cash reserve target, see Table B (above), of three months or 25% of annual operation and maintenance (1) is a frequently used primary element of a cash reserve policy. Line 2 covers the risk and peril system facilities are exposed to, like weather, accidents and vandalisms. The 1% of utility plant is typical; however, a tornado, earthquake or ice storm prone region utility may choose a higher percentage. Deposits (3) and Debt Service (4) are contract obligations so 100% is required. The most subjective element is for capital improvements elements Lines 5 & 6. Typically we recommend between 10% and 20%; higher percentages for utilities with more aged utility plant and where more construction is needed for replacements and renewals. A lower percent may be recommended for utilities with high growth rates and where more of construction is expansion work.

FINANCIAL FORECAST AND FIVE-YEAR RATE TRACK

Table C below shows the recommended annual 0.0% rate changes that are recommended for FYE 2013 through FYE 2015 (line f) and 2.7% for 2016 and 2017. For this study the focus is on recommending the rate adjustments for the January of 2013 and again in January of 2014. This rate adjustment will <u>net the same revenues</u> however the rate design will move rate classes closer to COS.

EXECUTIVE SUMMARY

Oak Creek, CO
2012 Electric Financial Plan, Cost of Service
And Rate Design Study Update

TABLE C - PROJECTED OPERATING STATEMENTS & CASH FLOW WITH 5-YEAR RATE TRACK

	FYE December		2011	2012	2013	2014	2015	2016	2017
a	Sales Growth Base Load		3.4%	-2.3%	0.5%	0.5%	0.5%	0.5%	0.5%
b	Administration Inflation		3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%
c	General Inflation		3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%
e	Purchase Power Adjustments		1.1%	5.3%	4.0%	4.1%	4.1%	4.1%	4.1%
f	**Rate Adjustments**		**3.4%**	**3.4%**	**0.0%**	**0.0%**	**0.0%**	**2.7%**	**2.7%**
	Effective date		**Jul. 2011**	**Jan. 2012**	**Jan. 2013**	**Jan. 2014**	**Jan. 2015**	**Jan. 2016**	**Jan. 2017**
1	**Revenues**								
2	Retail Sales		$ 668,430	$ 653,308	$ 693,759	$ 697,228	$ 700,714	$ 723,232	$ 746,473
3	Other Operating Rev		26,324	24,295	24,416	24,539	24,661	24,785	24,908
4	**Total Revenues**		**$ 694,754**	**$ 677,603**	**$ 718,176**	**$ 721,767**	**$ 725,375**	**$ 748,016**	**$ 771,381**
5	**Expenses**								
6	Power Purchased		$ 335,640	$ 340,905	$ 356,362	$ 372,820	$ 390,079	$ 408,194	$ 427,206
7	Capacity Payments		(27,531)	(30,808)	(30,808)	(30,808)	(30,808)	(30,808)	(30,808)
8	Production Power		19,563	17,230	17,747	18,279	18,828	19,393	19,974
9	Operation and Maintenance		30,004	35,800	36,874	37,980	39,120	40,293	41,502
10	Distribution		29,774	30,500	31,415	32,357	33,328	34,328	35,358
11	Adm. and Gen.		119,710	120,460	124,074	127,796	131,630	135,579	139,646
12	City Mgtm Services	10%			69,376	69,723	70,071	72,323	74,647
13	**Total O&M**		**$ 507,160**	**$ 514,087**	**$ 535,664**	**$ 558,425**	**$ 582,177**	**$ 606,978**	**$ 632,878**
14	Depreciation		$ 76,343	$ 79,343	$ 82,433	$ 85,616	$ 88,894	$ 92,270	$ 95,748
15	**Total Electric Expense**		**$ 583,503**	**$ 593,430**	**$ 618,097**	**$ 644,041**	**$ 671,070**	**$ 699,249**	**$ 728,626**
16	**Net Operating Income**		**$ 111,251**	**$ 84,173**	**$ 100,079**	**$ 77,726**	**$ 54,305**	**$ 48,767**	**$ 42,755**
17	**Net Income Target % of UPIS**	5.0%	**$ 19,793**	**$ 23,355**	**$ 27,024**	**$ 30,804**	**$ 34,697**	**$ 38,706**	**$ 42,836**
18	**Net Income Actual % of UPIS**		**28.1%**	**18.0%**	**18.5%**	**12.6%**	**7.8%**	**6.3%**	**5.0%**
19	COS Revenue Requirement			**$ 592,490**					
20	**Other Revenues & Expenses**								
21	Interest on existing LT Debt		(13,345)	$ (12,145)	$ (10,761)	$ (9,407)	$ (7,973)	$ (6,454)	$ (4,845)
22	**Total Profit / Loss**		**$ 97,906**	**$ 72,028**	**$ 89,318**	**$ 68,319**	**$ 46,332**	**$ 42,314**	**$ 37,910**
23	**Cash Inflows**								
24	Net Income		$ 97,906	$ 72,028	$ 89,318	$ 68,319	$ 46,332	$ 42,314	$ 37,910
25	Depreciation Expense		$ 76,343	$ 79,343	$ 82,433	$ 85,616	$ 88,894	$ 92,270	$ 95,748
26	Cash Inflows		**$ 174,249**	**$ 151,371**	**$ 171,751**	**$ 153,935**	**$ 135,226**	**$ 134,584**	**$ 133,658**
27	**Cash Outflows**								
28	Capital Improvements & CWIP		75,000	77,250	79,568	81,955	84,413	86,946	89,554
29	Principal on Existing Debt		20,355	$ 21,560	$ 22,939	$ 24,293	$ 25,727	$ 27,246	$ 28,855
30	Principal on New Debt								
31	**Cash Outflows**		**$ 95,355**	**$ 98,810**	**$ 102,506**	**$ 106,248**	**$ 110,140**	**$ 114,192**	**$ 118,409**
32	Change in Cash		**$ 78,894**	**$ 52,561**	**$ 69,244**	**$ 47,687**	**$ 25,086**	**$ 20,392**	**$ 15,249**
33	**Cash Balance**		**$ 519,453**	**$ 572,014**	**$ 641,258**	**$ 688,945**	**$ 714,031**	**$ 734,423**	**$ 749,672**
34	**Cash Balance Target**		**251,612**	**256,304**	**264,335**	**272,342**	**280,264**	**288,105**	**295,867**

FINDINGS AND RECOMMENDATIONS

Table D below shows that the residential rate class revenues are 6.8% over cost of service (COS), General Service rates are 17.0% over COS, and General Service Demand revenues under existing rates are 26.3% more than COS. A net zero rate change can be designed to bring the classes toward COS but limiting the change in bills to no greater than plus or minus 2.0% as discussed on page 1. After about 3 rate changes the residential would be at COS. The GS classes will take longer.

Line	Rate Class	Revenue Existing Rates	Cost of Service	difference from COS	
				$	% to COS
1	Residential	$ 424,560	$ 395,852	(28,707)	-6.8%
2	General Service	132,423	109,890	(22,533)	-17.0%
3	General Service Three-Phase	96,325	70,966	(25,359)	-26.3%
4	**Total**	**$ 653,308**	**$ 576,709**	**$ (76,599)**	-11.7%

Table C, above, shows that without revenue changes the 2012 Net Operating Income (line 16) is $84,173 or a ROI of 18.0%. This is well above the recommended target of $23,355 or 5.0% (line17 & 18). By 2017 with no increases the ROI is 0.5%, however by 2017, Cash Balance (line 33) is about $195,700 higher than the minimum reserves target (line 34) and it may be possible to delay the proposed 2.7% revenue increase in 2016 and 2017 even longer.

The recommendations for the City Council to consider are:

1) Consider directing staff and NMPP to design net-zero rate change to be effective January 1, 2013 and again January 1, 2014. The proposed rates will include the energy delivered to City facilities to be billed under the applicable general service rates. The base rate adjustments will be designed to move classes closer to a more fair and equitable recovery of costs by using the recommend rate design guideline of plus or minus 2.0% from the system average base revenue change of 0.0%. Thus, no class will get more than 2.0% bill increase and no class will get less than a 2.0% bill decrease from current rates.

   The proposed rates will be presented in Appendix A to the final report. A summary on typical bill impact estimates by rate class will be provided in Appendix B to the final report.

NMPP Energy ■ 1111 O Street - Suite 200 ■ Lincoln, NE 68508
■ Phone: 402.474.4759 ■ Fax: 402.474.0473
P.O. Box 95124 ■ Lincoln, NE 68509 ■ www.nmppenergy.org

2) Consider adding a Power Cost Adjustment (PCA) clause to the Rate Ordinance such that the Council can invoke such clause in cases of significant revenue changes that are necessary because of substantial increases in the Budgeted cost of power or other electric department fiscal emergency that is estimated to be greater than a 10% deviation in a fiscal year power cost budgeted. For example the clause could read as follows:
3) All rates are subject to a Power Cost Adjustment as may be set from time-to-time by the City Council. The Power Cost Adjustment (PCA) clause may be invoked for periods of no longer than 12 months in cases when significant revenue changes are necessary because of substantial increases/decreases in the cost of power and/or other electric department emergencies that are estimated to be greater than a 10% deviation in FY power costs budgeted. In some cases the City's wholesale provider of electric power may bill an adjustment clause for a period of time and these costs may be passed on with losses using the PCA.

   For 2012 10% of budgeted power cost in the rate base is approximately $36,500. This divided by the system annual sales gives a PCA of $.005/KWh and adds about $3.40 to the average residential customer's bill for 680 KWh/month.

4) Rate changes should be reviewed every other year and adjusted as necessary to recover higher or lower than assumed revenue, load and cost escalations. Rate adjustments for CY 2015 and 2016 will be designed by NMPP Energy as part of the four-year Cost of Service and Rate Design Study Agreement. This will continue the process of bringing classes closer to their actual cost of service, returning to a net operating income of at about 5.0% of plant investment, and retaining a minimum cash reserve as determined by the Council's Cash Reserve targets.

NMPP Energy ■ 1111 O Street - Suite 200 ■ Lincoln, NE 68508
■ Phone: 402.474.4759 ■ Fax: 402.474.0473
P.O. Box 95124 ■ Lincoln, NE 68509 ■ www.nmppenergy.org