BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Application of Rocky Mountain Power for Authority To Increase its Retail Electric Utility Service Rates in Utah and for Approval of Its Proposed Electric Service Schedules and Electric Service Regulations.	DOCKET NO. 11-035-200 Exhibit DPU 3.0 Dir-Rev Req Testimony and Exhibits Richard S. Hahn

FOR THE DIVISION OF PUBLIC UTILITIES
DEPARTMENT OF COMMERCE
STATE OF UTAH

REDACTED

Testimony of

Richard S. Hahn

June 11, 2012

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ATTACHMENTS

DPU Exhibit 3.1 Dir-Rev Req, Resume of Richard S. Hahn

DPU Exhibit 3.2 Dir-Rev Req, City Creek Expenditure Requisition ("ER")

DPU Exhibit 3.3 Dir-Rev Req, City Creek Authorization Request ("APR")

DPU Exhibit 3.4 Dir-Rev Req, City Creek Investment Appraisal ("IAD")

DPU Exhibit 3.5 Dir-Rev Req, City Creek Project Change Notice ("PCN")

DPU Exhibit 3.6 Dir-Rev Req, Listing of Generic Projects Analyzed

DPU Exhibit 3.7 Dir-Rev Req, Listing of Specific Projects Analyzed

I. Introduction

Q: Please state your name, business address and title.

A: My name is Richard S. Hahn. I am employed by La Capra Associates, Inc. ("La Capra Associates") as a Principal Consultant. My business address is One Washington Mall, Boston, Massachusetts, 02108.

Q: On whose behalf are you testifying?

A: The Division of Public Utilities of the State of Utah (the "Division").

Q: Please summarize your educational and professional experience.

A: I received my Bachelor's in Science, Electrical Engineering, in 1973, and my Masters in Science, Electrical Engineering, in 1974, both from Northeastern University. I received my Masters in Business Administration from Boston College in 1982. Since joining La Capra in 2004, I have worked on many projects related to energy markets, utility resource planning projects, forecasts of wholesale market prices, and asset valuations. Prior to joining La Capra, I was employed by NSTAR Electric & Gas (formerly Boston Edison Company) from 1973 to 2003, where I was responsible for, among other activities, integrated resource planning and procurement of power supplies via Requests For Proposals ("RFPs") and bilateral contract negotiations. Throughout my career, I have gained and demonstrated considerable experience and expertise in utility planning activities. I am a registered professional electrical engineer in the Commonwealth of Massachusetts. My resume is provided in DPU Exhibit 3.1 Dir-Rev Req.

Q: What is the purpose of your testimony?

A: La Capra Associates was retained by the Division to assist in reviewing the Application of Rocky Mountain Power ("RMP" or the "Company") seeking approval from the Public Service Commission of Utah ("Commission") to increase electric rates. The scope of our assignment was to review the proposed additions to plant in-service. This direct testimony presents the results of and the conclusions from that review.

Q: Have you previously testified before the Public Service Commission of Utah?

A: Yes. I testified in Docket No. 10-035-126 regarding the Application of Rocky Mountain Power for Approval of a Significant Energy Resource Decision Resulting from the All Source Request for Proposals. And I testified in Docket No. 10-035-124 regarding the Application of Rocky Mountain Power for Authority to Increase Its Retail Electric Utility Service Rates in Utah and for Approval of Its Proposed Electric Service Schedules and Electric Service Regulations.

II. Executive Summary of Testimony

Q: Can you summarize the results and conclusions of your review of the Application in this proceeding?

A: The results and conclusions of my review can be summarized as follows.

- I find that the Company's written capital planning and governance processes themselves are reasonable.

- The Company has not always followed its capital planning process for many proposed capital project. In some cases, adequate documentation has not been provided or the Company has acknowledged that such documentation does not yet exist.
- The need for some of the examined capital projects no longer exists.
- Some proposed projects have in-service dates that are different than the in-service dates included in the Company's projected plant additions.
- The Company projects plant additions from July 2011 through May 2013 to be $2,617 million. The test year plant in-service is based upon the thirteen-month average from May 2012 through May 2013. From July 2011 through April 2012, projected plant additions are approximately $973 million, and $1,644 million is projected to be added from May 2012 through May 2013.[1]
- Based upon my review of the original filing, I find that several adjustments to the Company's proposed capital spending from July 2011 to May 2013 should be made. Specifically, I recommend that the $2,617 million in capital spending proposed by the Company be reduced by $127.6 million. Utah's share of this reduction is about $66 million. Figure 1 below summarizes the adjustments to the Company's proposed capital spending for the July 2011 to May 2013 period.
- Division Staff has estimated that the effect of reducing projected plant additions by the above amount is to reduce the revenue requirement by $6.7 million. This change is described further in the testimony of Matthew Croft on behalf of the Division.

[1] A portion of total Company plant additions will be allocated to Utah customers, as described later in this testimony. Unless specifically noted as Utah's share, the costs discussed in this testimony are total Company costs.

Figure 1

La Capra Associates Proposed Adjustments to Requested Plant Additions
($000)

Project Type	Project	Plant Type	Factor	RMP Proposed Total 6/2011 to 5/2013	LCA 23-month total	Proposed Change	Utah Allocator	Utah Share of Proposed Change	Comments
Generic	Upgrades and Enhancements	Intangible	SO	$17,638	$4,114	$13,523	42.85%	$5,795	actual-trend well below projected; no specific basis offered
Generic	Corp Optimization	Intangible	SO	$4,388	$926	$3,461	42.85%	$1,483	actual-trend well below projected; no specific basis offered
Generic	Total Obsolescence Management	General	SO	$21,191	$13,765	$7,426	42.85%	$3,182	actual-trend well below projected; no specific basis offered
Generic	U4--Functional Upgrade - Spare Equipment Addition	Distribution	UT	$3,963	$118	$3,845	100.00%	$3,845	actual-trend well below projected; no specific basis offered
Generic	R2--Replace - Substation - Meters and Relays	Transmission	SG	$1,410	$331	$1,079	43.15%	$466	actual-trend well below projected; no specific basis offered
Generic	RI--Replace - Storm and Casualty	Transmission	SG	$1,055	$398	$657	43.15%	$284	actual-trend well below projected; no specific basis offered
Generic	RE--Replace - Overhead Transmission Lines - Poles	Transmission	SG	$2,656	$1,787	$869	43.15%	$375	actual-trend well below projected; no specific basis offered
Generic	MR--Mandated - Regional or National Regulatory	Transmission	SG	$2,082	$409	$1,672	43.15%	$722	actual-trend well below projected; inadequate basis offered
Generic	MR--Mandated - Regional or National Regulatory	Transmission	SG	$1,497	$124	$1,373	43.15%	$592	actual-trend well below projected; inadequate basis offered
Specific	W-1799 Replace three generators company wide	Other	SG	$319	$0	$319	43.15%	$138	No Documentation
Specific	Naughton U3 OH Coal Combustible Dust CY 11	Steam	SG	$262	$0	$262	43.15%	$113	Naughton unit 3 to be converted to natural gas
Specific	Naughton U3 3-4 Coal Mill Rebuild CY11	Steam	SG	$249	$0	$249	43.15%	$108	Naughton unit 3 to be converted to natural gas
Specific	Naughton U3 3-3 Coal Mill Rebuild CY11	Steam	SG	$211	$0	$211	43.15%	$91	Naughton unit 3 to be converted to natural gas
Specific	Naughton U3 3-1 Coal Mill Rebuild CY12	Steam	SG	$189	$0	$189	43.15%	$82	Naughton unit 3 to be converted to natural gas
Specific	Naughton U3 3-2 Coal Mill Rebuild CY12	Steam	SG	$189	$0	$189	43.15%	$82	Naughton unit 3 to be converted to natural gas
Specific	Naughton U3 3-4 Coal Mill Rebuild CY12	Steam	SG	$189	$0	$189	43.15%	$82	Naughton unit 3 to be converted to natural gas
Specific	Lake Side 2 Interconnect	Transmission	SG	$19,233	$0	$19,233	43.15%	$8,300	Generator interconnection for unit in-service after test year ends
Specific	Terminal Substation	Transmission	SG	$42,107	$15,600	$26,508	43.15%	$11,439	Increased cost estimate not justified, new in-service date is 12/2012
Specific	City Creek Center: New 40 MW Development for PRI Phase II	Distribution	UT	$17,775	$3,675	$14,100	100.00%	$14,100	Adjust CIAC to be consistent with Company policy
Specific	Skypark Build New 138-12 5kV Substation	Distribution	UT	$8,064	$6,109	$1,955	100.00%	$1,955	$1.2M land not used; $0.8M expense doubel-counted
Specific	Cottonwood Prep Plant-System Improvement	Mining	SE	$4,039	$0	$4,039	42.95%	$1,735	Documentation provided shows July 2013 in-service date
Specific	Energy West Deer Creek Mine CAP Forecast	Mining	SE	$8,653	$3,277	$5,376	42.95%	$2,309	Documention provided shows $3,277,000
Specific	Scipio Pass - Mineral Mountain Microwave	General	SG	$2,780	$1,480	$1,300	43.15%	$561	Documentation provided shows only $1,480,000 approved.
Specific	2GHz Microwave Replacement: Pavant Sub to Delta Service Center	General	UT	$350	$134	$216	100.00%	$216	Documentation provided shows only $134,000 approved.
Specific	JB U2 Replace Cooling Tower 12/13	Steam	SG	$7,110	$0	$7,110	43.15%	$3,068	No Documentation; Unlikely to be completed by May 2013
Specific	Naughton U0 BART Study for CAM	Steam	SG	$214	$0	$214	43.15%	$92	Limited outdated documentation; Calendar year 2007-2008 project
Specific	Currant Crk U2 CSA Variable fee 24k - CTB MI	Other	SG	$8,726	$0	$8,726	43.15%	$3,766	No Documentation; Speculative to pre-judge first major inspection
Specific	Cholla U4 FABRIC FILTER BAG REPLACE CY13	Steam	SSGCH	$372	$0	$372	41.89%	$156	No Documentation or project description
Specific	Hermiston U0 Auxiliary Boiler	Other	SG	$1,608	$0	$1,608	43.15%	$694	No Documentation or project description
Specific	Naughton U0 D10 Replacement	General	SG	$1,340	$0	$1,340	43.15%	$578	No documentation provided.
Sum			30	$179,858	$52,248	$127,610		$66,408	
	Generic Project Subtotal		9	$55,878	$21,973	$33,905		$16,744	
	Specific Project Subtotal		21	$123,980	$30,275	$93,705		$49,664	
	Total Generic Project Reviewed		53	$242,912					
	Total Specific Project Reviewed		53	$258,167					

III. Overview of Projected Plant In-Service

Q: Can you summarize the Company's proposed additions to plant in-service?

A: In this rate case, the Company proposes to use the average plant in-service balance for thirteen months from May 2012 to May 2013. At the time the filing was prepared, it is my understanding that the Company had actual plant in-service data as of June 30, 2011. The Company projected net plant additions by month over the 23 month period from July 2011 through May 2013. Plant additions were projected by compiling estimates of proposed capital spending on various projects. A project with a specific in-service date was added to the plant in-service database in the month that the project was expected to be in-service. For projects without any specific in-service date, spending was spread across the 23 months using historical distributions. Monthly retirements were estimated using statistical analysis. Net plant in-service at the end of any given month equals the beginning balance plus plant additions less plant retirements.

The Company projects to invest $2,617 million in new capital projects between June 2011 and May 2013. There are 1,206 individually identified projects that sum to this total. Figure 2 below provides a summary of the Company's proposed additions during this 23 month period. The data in Figure 2 is broken down by plant category, project type (either "generic" or "specific"), and by spending level. A specific project is typically a large discrete investment to address a particular, identified need. For example, if load growth causes transformers at a particular substation to be overloaded, the Company will replace those transformers with ones of higher capacity. A generic project is one where many small capital spending items may be aggregated into one cost category, such as storm costs. There is typically no single in-service date for these generic projects.

Figure 2

11-035-2000 SUMMARY OF PROJECTED CAPITAL EXPENDITURES
June 2011 to May 2013

Sum of Costs

		Generic				Specific				
Account	Category	>$5M	$5M to $1M	<$1M	Total	>$5M	$5M to $1M	<$1M	Total	Grand Total
312	Steam Plant					603,970,717	139,268,552	126,836,909	870,076,178	870,076,178
355	Transmission Plant	17,028,694	46,062,416	25,717,555	88,808,665	614,987,107	66,751,670	7,620,650	689,359,426	778,168,091
364	Distribution Plant	136,433,771	113,680,945	42,091,220	292,205,936	58,765,006	40,726,691	2,038,742	101,530,439	393,736,374
332	Hydro Plant					240,947,976	38,508,012	19,769,873	299,225,862	299,225,862
397	General Plant	45,400,703	33,247,879	9,694,732	88,343,314	55,578,380	18,345,073	7,812,874	81,736,326	170,079,640
343	Other Plant					17,452,951	9,718,542	18,885,604	46,057,097	46,057,097
303	Intangible Plant	17,637,637	4,387,531	1,816,226	23,841,394		1,870,940		1,870,940	25,712,334
302	Intangible Plant						4,165,419	5,996,730	10,162,148	10,162,148
399	Mining Plant					8,652,600	9,076,571	6,854,347	24,583,519	24,583,519
Grand Total		216,500,805	197,378,771	79,319,732	493,199,308	1,600,354,736	328,431,469	195,815,730	2,124,601,934	2,617,801,242

Count of Line Items

		Generic				Specific				
Account		>$5M	$5M to $1M	<$1M	Total	>$5M	$5M to $1M	<$1M	Total	Grand Total
312	Steam Plant					17	70	386	473	473
355	Transmission Plant	2	25	96	123	15	26	21	62	185
364	Distribution Plant	12	50	144	206	7	15	6	28	234
332	Hydro Plant					9	19	57	85	85
397	General Plant	3	14	57	74	4	8	21	33	107
343	Other Plant					2	5	62	69	69
303	Intangible Plant	1	1	4	6		1		1	7
302	Intangible Plant						1	25	26	26
399	Mining Plant					1	4	15	20	20
Grand Total		18	90	301	409	55	149	593	797	1,206

IV. Historical Summary of Capital Spending / Plant Additions

Q: How does the Company's projected capital spending for the purposes of this rate case compare to recent actual spending?

A: The projected $2,617 million over 23 month equates to annual spending of about $1,365 million. Since being acquired by Mid-American Energy in early 2006, the Company has invested on average $1,667 million per year in new plant, with $1,352 million added in 2011. Figure 3 below provides this historic data based on the Company's annual FERC Form 1 reports.

Figure 3

PacifiCorp Plant Additions 2005 through Test Year
($millions)

Plant Category	12/31/2005	12/31/2006	12/31/2007	12/31/2008	12/31/2009	12/31/2010	12/31/2011
distribution	$228	$239	$283	$282	$257	$222	$243
general	$94	$81	$72	$75	$76	$89	$131
hydro	$20	$15	$19	$43	$57	$32	$80
intangible	$72	$34	$18	$81	$33	$101	$51
other prod	$187	$360	$586	$780	$588	$252	$27
steam	$136	$322	$186	$331	$273	$687	$614
transmission	$92	$121	$184	$217	$291	$1,030	$204
adj	$0	$0	($0)	$303	$3	$11	$1
Grand Total	$830	$1,173	$1,346	$2,111	$1,578	$2,425	$1,352

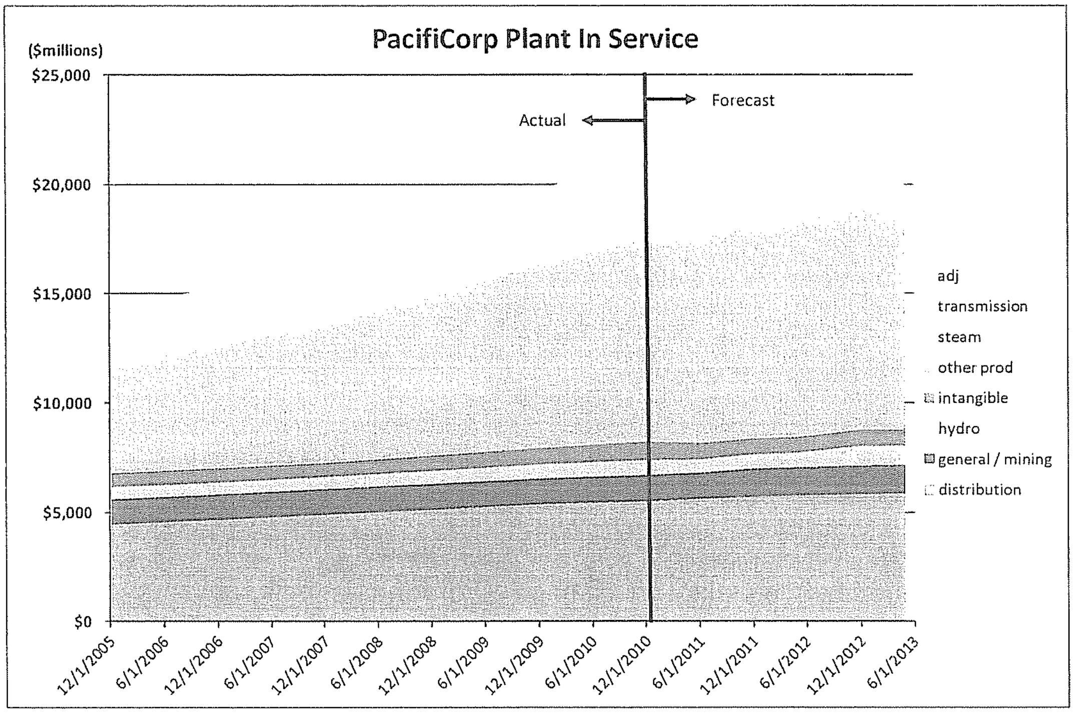
The Company projects retirements of about $593 million from June 2011 through May 2013, resulting in net plant added of $2,617 million in new capital investments less $593 million in retirements, or $2,024 million. Thus, plant in-service from June 2011 through May 2013 increases by $2,024 million to $24,012 million from $21,988 million. Figure 4 below shows plant in-service balances from 2005 through the test year projection in this case. From 2005 through 2010, plant in-service increased 52% from $14,336 million to $21,785 million, or 10% per year. Since then the growth in plant in-service has slowed to about 4% per year.

Figure 4

PacifiCorp Plant In Service 2005 through Test Year
($millions)

Plant Category	12/31/2005 [1]	12/31/2006 [1]	12/31/2007 [1]	12/31/2008 [1]	12/31/2009 [1]	12/31/2010 [1]	6/30/2011 [2]	12/31/2011 [2]	5/31/2012 [2]	12/31/2012 [2]	5/31/2013 [2]
distribution	$4,446	$4,653	$4,885	$5,106	$5,329	$5,487	$5,562	$5,689	$5,750	$5,805	$5,844
general / mining	$1,152	$1,164	$1,182	$1,197	$1,206	$1,214	$1,235	$1,299	$1,302	$1,312	$1,298
hydro	$528	$540	$534	$575	$628	$657	$589	$629	$631	$869	$866
intangible	$672	$678	$671	$721	$752	$848	$760	$761	$754	$758	$751
other prod	$457	$811	$1,383	$2,157	$3,060	$3,308	$3,310	$3,308	$3,293	$3,301	$3,297
steam	$4,502	$4,782	$4,888	$5,111	$5,325	$5,927	$6,077	$6,319	$6,612	$6,739	$6,786
transmission	$2,578	$2,689	$2,875	$3,055	$3,343	$4,339	$4,455	$4,515	$4,583	$4,726	$5,171
adj	$0	$0	($0)	$303	$3	$4	$0	$0	$0	$0	$0
Grand Total	$14,336	$15,317	$16,417	$18,225	$19,646	$21,785	$21,988	$22,519	$22,925	$23,510	$24,012
		6.8%	7.2%	11.0%	7.8%	10.9%	0.9%	2.4%	1.8%	2.6%	2.1%

notes:
[1] from FERC Form 1
[2] RMP filing



V. Summary of the Company's Capital Planning Process

Q: What is the Company's internal process for developing its plans for capital spending?

A: DPU Data Requests 2.15 and 2.16 asked the Company to provide copies of any accounting manuals and procedures or protocols for internal approval of capital projects. In its responses the Company provided three documents: (1) a Capitalization Policy, (2) Corporate Governance and Approvals Process, and (3) 2010 to 2019 Budget and 10-Year Plan Guidelines. From a review of these documents, it appears that the Company's process is to have each of its business units identify the potential need for capital investments. For each such identified project, the business unit must request authorization to make the capital investment. An Appropriation Request ("APR") or an Expenditure Request ("ER") is the documentation that is required for approval to spend money on a capital project. A capital project is defined as an asset that is used in the Company's operations or provides benefit to the Company, and has an expected useful life of one year or greater. A capital project must also meet a specific definition of a capital asset with a defined property retirement unit ("PRU"). There does not appear to be a threshold limit for these forms. The Capitalization Policy states that "APR or ER authorization is required for any capital project expenditure".

In addition to the APR / ER, many requests for approval to spend funds on capital projects are accompanied by an Investment Appraisal Document ("IAD"). An IAD includes a summary of the scope of the project, a discussion of the need, the alternatives considered, and the results of the Company's standard financial evaluation model. Another document that is often prepared for a capital project is a Project Change Notice ("PCN"). A PCN appears to be created whenever there is a significant change in the project, such as an increase in the project cost or a change in the project schedule.

Q: Can you provide examples of these documents from the information provided by the Company?

A: I have attached to my testimony exhibits that provide examples of the above documentation for capital projects.

- DPU Exhibit 3.2 Dir-Rev Req, City Creek Expenditure Requisition ("ER")
- DPU Exhibit 3.3 Dir-Rev Req, City Creek Appropriation Request ("APR")
- DPU Exhibit 3.4 Dir-Rev Req, City Creek Investment Appraisal ("IAD")
- DPU Exhibit 3.5 Dir-Rev Req, City Creek Project Change Notice ("PCN")

Q: What information is provided in the documentation entitled Corporate Governance and Approvals Process?

A: This documentation describes how the authority to approve capital projects is delegated to various levels of management. For example, the President of Rocky Mountain Power can approve capital projects with estimated costs up to $25 million. For projects greater than $25 million, approval from the PacifiCorp CEO is required. The governance process document also establishes organizational limits on who can approve certain types of projects. For example, all hydro relicensing projects require the approval of the PacifiCorp CEO, regardless of cost. Information technology projects must be approved by the PacifiCorp IT organization. This delegation of authority is intended to assure that large projects are reviewed at the appropriate levels of management and that proper controls are in place to plan for and monitor capital spending.

Q: Are these the only documentation that you would expect to be available for capital projects?

A: No. These documents are only for gaining corporate authorization to spend the funds. They represent the paperwork for the financial operations of the Company, including regulatory cost recovery. I would expect that there would be other documentation for most capital projects, such as engineering and other technical studies. These technical studies would describe more fully the need for the project including the timing, the alternatives considered, the basis for the cost of each alternative, the technical and economic evaluation of the alternatives, and a discussion of how the preferred or recommended project was chosen. It would be my expectation that such documentation would be prepared prior to the development of APRs, ERs, and IADs, and that such documentation would be reviewed prior to approval of the APR / ER.

Q: Does the Company's process include monitoring and post-completion assessments?

A: Yes. The governance process states that Post Investment Reviews ("PIRs") are required for a certain percentage of completed capital projects. A PIR is an after-the-fact analysis that evaluates business control of the project and any lessons learned. They are required for 30% of projects greater than $10 million, 5% of projects between $1 million and $10 million, and 2% of projects between $250,000 and $1 million. An Interim Project Appraisal ("IPA") may be performed for projects with a duration greater than 1 year.

Q: What is your assessment of the Company's capital planning process?

A: The approval and governance processes described above are similar to what I have seen at other utilities. The implementation of this process and the compilation of all appropriate documentation, including the technical analyses and supporting studies, are the keys to a defensible plan. APRs / ERs / IADs / PCNs should be available for all capital projects. These are the key documents as they represent an approved level of capital spending. It is possible that certain projects may be included in the 10-year

Capital Plan that do not yet have approval or authorization. Thus, the fact that a project is included in a capital budget is not sufficient to justify inclusion in a forecast of plant in-service for a forward looking test year. The up-to-date APRs, ERs, IADs, and PCNs should provide the latest basis upon which to base a forecast of plant in-service.

VI. Categories of Capital Projects

Q: Earlier in this testimony, you discussed generic and specific projects. Can you explain further how you chose these two categories and how the Company's capital database was disaggregated into these categories?

A: In response to DPU Data Request 2.1, details were provided on 1,206 individual capital projects. As shown in Figure 2 above, I have classified 409 of these projects as generic. By that, I mean that these projects do not have a specific in-service date and they are not associated with specific pieces of equipment or investments. These projects are for capital investments in broad categories. For example, the Company has included capital expenditures for a project named "Replace - Storm and Casualty". The Company does not project exactly when storms will occur, nor what specific facilities will be replaced. However, from experience, it knows that it typically spends capital dollars on storm restoration each year. Projects such as this are treated differently from specific projects, where a specific expected need exists and the facilities to be installed and the installation schedule can be predicted. Generic projects are not assigned an APR number. So, the 409 projects listed in the capital database that did not have an assigned APR and had various in-service dates were deemed to be generic projects. A review of the titles of these projects confirmed that designation.

VII. Selection of Generic Projects

Q: How many of the 409 generic capital projects shown in Figure 2 did you examine in further detail?

A: It would not be practical to examine all 409 projects in detail. I did not review any generic projects with total projected expenditures less than one million dollars. Furthermore, many generic projects are directly assigned to other states besides Utah. Since customers of RMP would not have to pay for any of these projects that are directly assigned or allocated to other states, I did not review them. I reviewed all 53 generic projects greater than one million dollars that were directly assigned to Utah or shared across the PacifiCorp system.

Of the 53 projects reviewed, 27 projects were associated with transmission plant, 18 were associated with distribution plant, six were associated with general plant, and two were associated with intangible plant. Figure 5 below provides a summary of the generic projects analyzed. The total cost of the 53 projects reviewed is about $243 million, or roughly half the $493 million total for all generic projects in the Company's Capital Database. DPU Exhibit 3.6 Dir-Rev Req provides a listing of the individual generic capital projects analyzed.

Figure 5

GENERIC PROJECTS ANALYZED

Plant Type	count	Projected Plant Additions ($000)
Transmission	27	$63,091
Distribution	18	$111,377
General	6	$46,419
Intangible	2	$22,025
Total	53	$242,912

VIII. Analysis of Generic Projects

Q: Please explain how you analyzed the projected capital spending for generic capital projects.

A: Because generic capital projects are by their nature not tied to a specific need or a single asset or investment, it was necessary to analyze spending trends and combine that analysis with any additional explanation provided by the Company in responses to data requests. The Company has stated that it also examines recent spending trends in establishing its projected plant additions for generic projects.[2] I will illustrate the analysis of projected capital spending for the generic project named "Total Obsolescence Management".

Q: Can you describe how you analyzed projected capital spending for the project named Total Obsolescence Management?

[2] See responses to DPU Data Requests 19.1(c), 19.2(b), 19.5(d), 19.6(c).

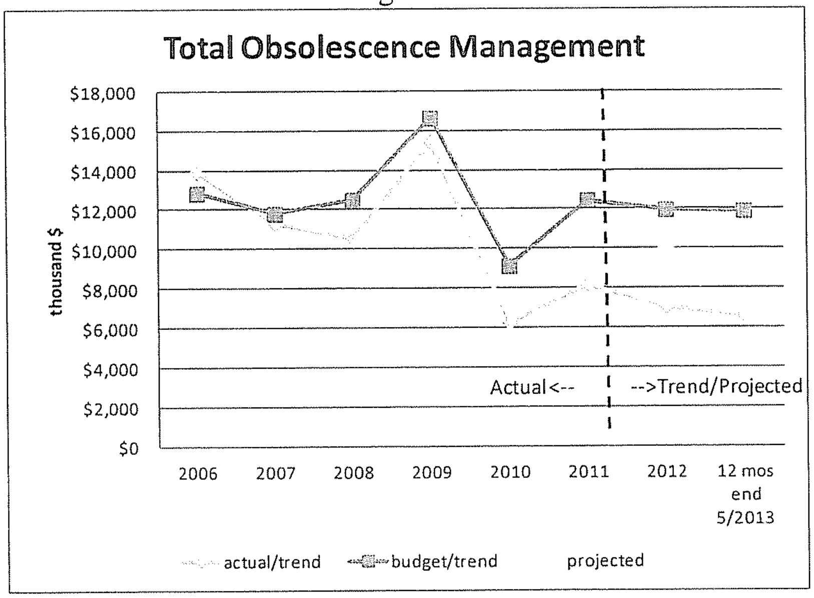
A: In the category of general plant, the Company has projected that the capital additions for the Total Obsolescence Management project will be $21.2 million between June 2011 and May 2013. In the response to DPU Data Request 19.5, the Company provided the following explanation of this project.

> *Technology Obsolescence Management is a strategy of planned replacement of data and voice infrastructure hardware and software components based on evaluation of company needs and expected obsolescence according to key vendors' and service providers' end of life policies, limited by the Company's planned capital expenditures. This strategy is designed to assure the infrastructure continues to serve the business needs at the lowest overall costs. Expenditures associated with these activities are typically numerous but may individually be relatively small in magnitude. Expenditures are budgeted by evaluating historical trends, age of assets currently in-service and other known facts or anticipated business need. Planned annual expenditures are apportioned to months based on historical monthly spending patterns and other known facts. Please refer to Attachment 19.5b for a copy of the Technology Obsolescence Management description.*

Q: How did you analyze the projected spending request for this project to be included in rate base?

A: Since the Company stated that it established capital budgets for this project based upon, among other considerations, historical spending, I examined annual historical actual and budgeted amounts for this project from 2006 to 2011 In the response to DPU Data Request 19.5, the Company provided such data. My analysis of this data is summarized in Figure 6 below.

Figure 6



Data provided by the Company is shown for both actual spending and budgeted amounts through 2011. For both actual and budgeted spending, historical data was used to develop trends which were used to project annual spending for two 12-month periods: calendar year 2012 and the twelve months ending May 31, 2013.[3] The Company's projected capital expenditures for both of these 12-month periods are also shown. From the data in Figure 6 above, I conclude that the Company has consistently spent less than the amount budgeted for this cost category. Its projected test year spending is considerably higher than recent actual spending or projected spending based upon trends. The Company's projected spending is 35% higher than the trend. Therefore, I reduced the Company's projected capital additions for the 23-month period (June 2011 to May 2013) by 35%, from \$21.2 million to \$13.8 million. The recommended reduction for this project is \$7.4 million. Figure 7 below shows the calculation of this adjustment.

[3] The TREND function in Excel was used to develop these trends.

Figure 7
Analysis of Capital Spending for Total Obsolescence Management

RMP proposed total 6/2011 to 5/2013	type	2006	2007	2008	2009	2010	2011	2012	12 mos end 5/2013	adjust ment	LCA 23 month total
$21,191	actual/trend	$13,873	$11,261	$10,514	$15,407	$6,247	$8,180	$7,052	$6,593	35.0%	$13,765
	budget/trend	$12,819	$11,779	$12,472	$16,612	$9,095	$12,413	$11,937	$11,866		
	projected							$10,395	$10,611		

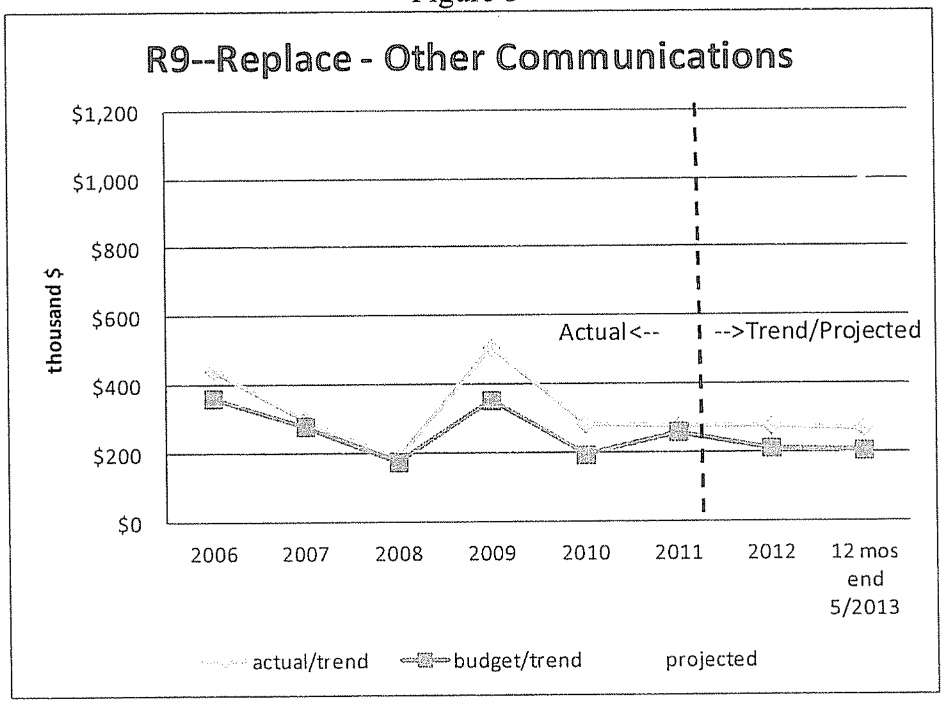
Q: Has the Company provided any additional detail that would cause you to revise the estimate developed above?

A: No. In response to a data request for explanation of the project and how the projected capital expenditures were calculated, the Company provided DPU Data Request 19.5 Attachment 19.5(b). The information provided in attachment 19.5(b) is a very general overview of Technology Obsolescence Management Strategy but it does not provide any additional details that would be useful in determining the appropriate amount of capital spending to be included in a future test year.

Q. Do you recommend reducing the budgeted capital additions for all generic projects that are projected to be higher than their historical trends?

A. No. Through discovery, the Company was provided the opportunity to explain any variance between their projected expenditures and historic spending trend. In several cases, I found their explanations sufficient. Only where adequate documentation was provided did I recommend the full budgeted amount. For instance, Figure 8 below shows my trend analysis of a different generic general plant project, "R9 – Replace – Other Communications". Similar to the "Total Obsolescence Management" project shown above, the projected expenditures for this project are well above historic trend levels. In this case, however, the work papers provided in response to DPU Data Request 19.5(d) showed sufficient basis for projecting these higher levels of spending. As a result, I recommend that the full budgeted amount for this project be included in the test year.

Figure 8



Q: Was the process described above used to examine the projected capital spending for other generic projects?

A: Yes. The information provided in Figures 5, 6 and 7 and the analysis described above were developed for all 53 generic projects I examined. This information is provided in an excel spreadsheet file named "Hahn Workpapers for Generic Projects.xlsx", which accompanies this testimony.

IX. Selection of Specific Projects Reviewed

Q: Please describe the scope of your review of the "specific" projects?

A: Of the $2.6 billion in capital expenditures forecast by the Company from June 2011 to May 2013, more than $2.1 billion is budgeted for 797 specific projects. In contrast to "generic" projects, these line items contain projected expenditures for discrete projects that will be completed and placed in-service on a specific date by May 2013. It was beyond the scope of my assignment to examine each and every specific project included in the Company's projection. Instead, I selected a sample of 45 projects to review in some detail. Figure 9 below provides a summary of the specific projects analyzed. DPU Exhibit 3.7 Dir-Rev Req provides the full list of the specific projects that I reviewed.

Figure 9

SPECIFIC PROJECTS ANALYZED

Account	Plant Type	count	Projected Plant Additions ($000)
302	Intangible	1	$141
303	Intangible	1	$1,871
312	Steam Production	10	$52,338
332	Hydro Production	5	$23,768
343	Other Production	3	$10,653
355	Transmission	8	$87,767
360-373	Distribution	7	$42,815
397	General	4	$20,650
399	Mining	6	$18,165
Grand Total		45	$258,167

Q: How was the sample chosen?

A: Ten projects were included in my sample at the request of Staff. The ten projects are (1) Skypark Build New 138-12 5kV Substation; (2) Fort Douglas-New 138-12.5 kV Sub & Trans; (3) Copper Hills New 138-12 5kV Sub; (4) and (5) City Creek Center: New 40 MW Development for PRI Phase II[4]; (6) Cottonwood Prep Plant-System Improvement; (7) Section Extension-2011; (8) Deer Creek-(1) Used Continuous Miner; (9) Deer Creek-Reconstruct Longwall System; and (10) JB U4 Wet Stack Conversion. Based on my initial review of the plant addition descriptions of projects greater than $5 Million provided in McDougal Exhibit RMP (SRM-3), pp 8.6.31-39, I added two additional projects – Terminal Sub and Lake Side 2 Interconnect – for specific inclusion in my sample. The Terminal Sub project was chosen for review because I was aware of larger transmission projects in this area, and I wished to review this project for consistency with other investments. The Lake Side 2 Interconnect project was selected for review because it is associated with the construction of a new generating unit. The remaining 33 projects were selected randomly, subject to a few constraints discussed later in this section of my testimony.

Q. Why did you use random selection to choose most of the projects in your sample?

A. My recommendations for reductions in the capital budget for specific projects are limited only to the projects that I have directly reviewed. I do not represent that any statistically valid, quantitative extrapolations can be made from my sample to the full capital budget. However, by using a form of stratified random sampling, I believe my findings can provide qualitative indications of areas in the wider capital budget that may deserve

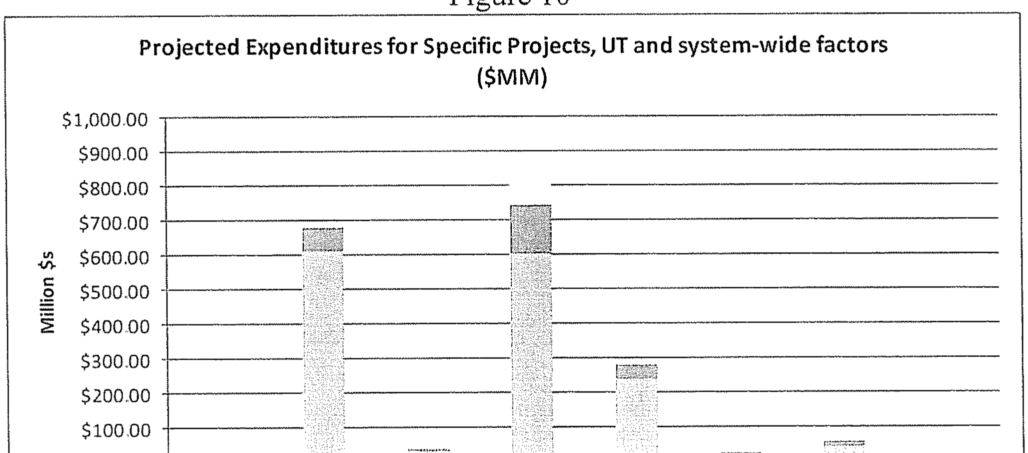
[4] This project counts as two because one component is a distribution plant project, and another component is a transmission plant project.

further study in this or future rate cases. These indications, though hardly conclusive, at least cannot be explained away by selection bias on my part (i.e. only picking projects for review that I have some reason to believe are flawed).

Q. Please describe how you selected your random sample of projects for review.

A. In order to ensure that my sample included projects in all plant type and size categories (less than $1 million, between $1 and $5 million, and greater than $5 million), I designed a stratified sample across 23[5] plant type/size categories. I used judgment to determine the number of projects to select in each category, taking into consideration the number of projects and size of total budget for each category. Figure 10 below shows the breakdown of projected expenditures for specific projects by category, and Figure 11 shows the distribution of projects in the sample.

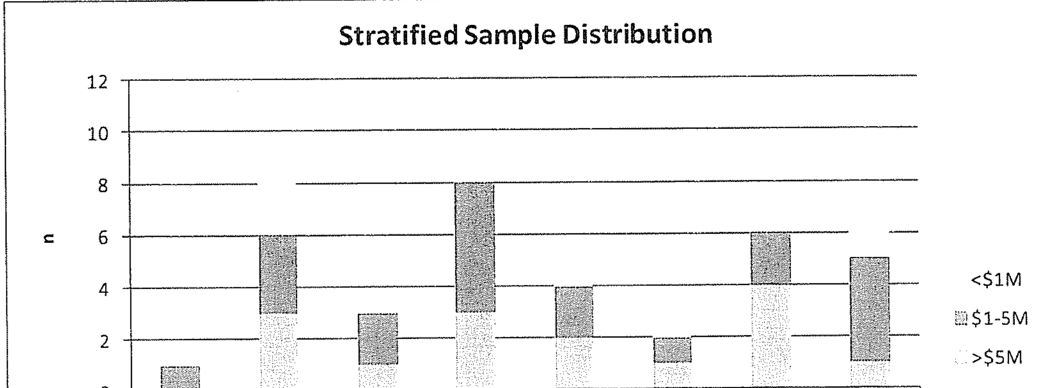
Figure 10



	Intangible	Transmission	General	Steam	Hydro	Other	Distribution	Mining
<$1M	$6.0	$7.6	$6.6	$126.8	$19.8	$18.9	$1.7	$6.9
$1-5M	$6.0	$66.8	$8.3	$139.3	$38.5	$9.7	$14.3	$9.1
>$5M	$-	$615.0	$30.1	$604.0	$240.9	$17.5	$45.7	$8.7

[5] Eight plant types times three size levels equals twenty four distinct categories. No projects fall into the Intangible/greater than $5 million category, so it is omitted.

Figure 11



	Intangible (302/303)	Transmission (355)	General (397)	Steam (312)	Hydro (332)	Other (343)	Distribution (364)	Mining (399)
<$1M	1	2	1	2	1	1	1	1
$1-5M	1	3	2	5	2	1	2	4
>$5M	0	3	1	3	2	1	4	1

Q. Once you determined the stratified sampling distribution, how did you randomly select projects for your sample?

A. First, I excluded certain projects from consideration. Division staff is conducting its own review of the Mona to Oquirrh 500/345kV line, so I removed it from the population of projects to be sampled. I also removed all projects whose costs would be allocated entirely outside of Utah, and those already approved in the previous rate case. To the more than 700 projects remaining in the database after these exclusions were made, I assigned a random real number between 0 and 1 using Microsoft Excel's random number generator function. Finally, I selected the projects from each plant type and size category with the highest randomly-generated number, until my sample size and distribution matched the plan shown in Figure 11 above.

Q: Did you examine any specific projects that were not included in your sample?

A: Yes. Subsequent to the development of the sample list, if I became aware of a new development that would affect a project that was not included in our sample, I did examine that project. For example, I became aware that the Company had proposed to convert the Naughton 3 generating unit to burn natural gas, rather than coal. This caused me to look for projects in the projected capital spending that involved Naughton Unit 3. This example is discussed further later in this testimony.

X. Analysis of Specific Projects

Q: Can you describe how you analyzed the specific capital projects?

A: My review of the specific projects consisted of an examination of the documentation provided by the Company in response to data requests. As a threshold matter, I first reviewed whether the project authorization papers for each project were complete. Projects without proper authorization should be and were excluded from the projected capital spending. This is appropriate because if the Company has not yet authorized a particular capital expenditure, it should not become part of the forward-looking test year plant in-service that will be paid for by RMP customers. If a project was properly authorized, I then examined the provided documentation to attempt to answer the remaining questions listed below. Based upon this review, I determined if any changes to the Company's proposed capital spending for the June 2011 to May 2013 time period were appropriate.

1) Does the appropriate corporate documentation and supporting technical studies exist?
2) Did the Company follow its own capital budgeting procedures?

3) What was the need for the project (i.e., load growth, reliability, environmental compliance, etc.)?
4) Does that need still exist?
5) Is the project scheduled to be in-service prior to the end of the test year?
6) Are the benefits to Utah commensurate with Utah costs?
7) Could / should the project be deferred?
8) How thorough / appropriate was the evaluation / justification?
9) Were there any cost overruns?
10) Are the costs reasonable?
11) Were any of the project components subject to competitive bidding?

Based upon this examination, I identified recommended adjustments to the capital spending projection prepared by the Company and filed as part of this rate increase. These specific adjustments are described in the ensuing sections.

A. Naughton U3 Projects

Q: **Please discuss the adjustments that you recommend that are related to the Naughton Unit 3.**

A: The Company had projected $1.289 million in capital spending for six specific projects to upgrade certain coal handling facilities for the Naughton Unit 3. Of this amount, three projects totaling $0.722 million were scheduled to be placed in-service between October and December 2011. The remaining three projects totaling $0.567 million were scheduled for December 2012. Each of these projects had an estimated cost of less than $1 million. Since the Company has proposed to convert this unit to burn natural gas, these capital projects should be removed from the projected spending total.

B. Lake Side 2 Interconnect

Q: Please describe the Lake Side 2 Interconnect project.

A: This Lake Side 2 Interconnect project calls for the construction of new transmission facilities to deliver the output from the proposed Lake Side 2 generating unit to the Company's transmission system.

Q. Should an adjustment be made to the projected plant in-service for this project?

A. Yes. The transmission facilities proposed to interconnect the new Lake Side 2 generating unit should be removed from the Company's forecast of plant additions for the test year. The generating unit is not scheduled to be in-service until May 2014 or after the May 2013 end date for the test year, and the transmission interconnection is not needed for other purposes prior to that. Before new power plants are declared commercially available and therefore placed into service, they undergo testing of the equipment and actually produce energy to demonstrate that the unit will deliver the benefits it is supposed to provide. A newly constructed generator is not placed in-service until it has successfully completed its testing phase. Obviously, you need the transmission interconnection in order to test the unit (i.e., actually make electricity). But the transmission interconnection is simply an integral part of the generating unit and should not be placed in-service ahead of the rest of the plant. The projected spending for this project should be removed from the Company's test year plant in-service.

C. Cottonwood Prep

Q: Please describe the Cottonwood Prep project.

A: The Cottonwood Prep Plant project is to construct additional coal handling facilities to increase coal storage capacity and improve reclaiming and blending capabilities.

Q. What adjustment should be made to the projected plant in-service for this project?

A. The documentation provided for the Cottonwood Prep Plant System Improvement project shows that the projected in-service date for this project is [redacted], which is after the test year. In the confidential response to DPU Data Request 29.7-1, the APR for this project clearly shows a projected in-service date of [redacted]. The projected spending for this project should also be removed from the Company's test year plant in-service.

D. Terminal Substation

Q: Please describe the Terminal Substation Project.

A: The Company proposes to replace two large station class transformers at the Terminal Substation. The cost of this project that is included in the Company's forecast of capital spending is $42.1 million. The listed in-service date is May 2012.

Q: What documentation has the Company provided in support of this request?

A: Based upon documents received in response to DPU Data Request 2.29, the Company has provided 5 electronic documents.

1. ER #0 Terminal Sub - replace transformers.pdf (2000)
2. IAD #1 Term Sub Replace 345-138 kV XFMR's.pdf (2009)
3. IAD #2 Term Sub Replace 2 345-138 kV XFMR's.pdf (2011)
4. PCN Terminal Transformers_APR 94000813 APPROVED.pdf (2011)
5. Terminal Substation GM.xls (2011)

The first two documents above were prepared in the spring of 2009. The last three documents were prepared in the spring of 2011. Some additional documentation was provided in response to DPU Data Request 26.15, but this material contains similar information as provided in the documents listed above.

The 2009 documentation was based upon a need to replace two existing transformers with two larger transformers. The Company's 2009 analysis states that under certain contingencies the two existing transformers can become overloaded. An assessment of the loading on these transformers under various system contingencies was provided, as was an assessment of alternatives to this project. The larger transformers would avoid the potential overloads, according to the Company. The two existing transformers will be re-used at the "Mona and Syracuse projects". The cost estimate in 2009 was $15.6 million and the expected in-service date was May 2012. Figure 12 below lists the major equipment assumed to be installed in the 2009 documentation.

Figure 12
Major Equipment in 2009 Documentation

Major Equipment	Description	No. of units
345-138 kV XFMR	345-138 kV, 700 MVA transformers	2
138 kV Breakers	138 kV breakers with a continuous rating of 3000 A (40 kA Fault Rating	1
138 kV Breakers	138 kV breakers with a fault rating of 63 kA	3

The 2011 documentation was based upon the same reliability need, and replaced the same two transformers. The estimated cost in 2011 was $48.6 million, including AFUDC and $2.0 million for contingencies. The latest document in the 2011 justification had a December 31, 2012 in-service date. The 2011 documentation makes reference to the project's eligibility for the 50% bonus depreciation.[6] Figure 13 below lists the major equipment to be installed in the 2011 documentation.

Figure 13
Major Equipment in 2011 Documentation

Major Equipment	Description	No. of units
345-138 kV XFMR	345-138 kV, 700 MVA transformers	2
138 kV Breakers	138 kV breakers with a continuous rating of 3000 A (40 kA Fault Rating	2
138 kV Breakers	138 kV breakers with a fault rating of 63 kA	20
138 kV Control House	Standard new Control Building (size?) with batteries, communicationsm HVAC,AC & DC Panels, etc.	1
Station Service	1-metal clad 12.47 kV circuit breaker in the 138/12.47 kV substation and 1 outdoor 12.47 kV circuit breaker in 46/12/47 kV sub	1

Q: Why did the cost increase to $48.6 million in 2011 from $15.6 million in 2009?

6 Bonus depreciation allows companies investing in new capital assets to depreciate 50% of the new asset in the first year of service, yielding additional tax benefits and serving as an incentive to invest.

A: The Company has not provided a detailed reconciliation of these two cost estimates. However, from the two figures above, it is clear more equipment is being added in the 2011 documentation. In the 2011 documentation, there are 20 138KV circuit breakers being replaced compared to only 4 138KV circuit breakers in the 2009 justification. In 2011, a new control house is also included, but was not included in 2009.

Q: Has the Company explained why it has added the additional equipment?

A: No. The 2011 PCN that seeks an increase in project funding to $48.6 million from $15.6 million still discusses only overloaded transformers. It states that the PCN "accommodates for the change in project scope and strategy resulting from assessment of the installation of larger transformers at the substation. It was determined that in order to ensure proper system reliability with the new capacity, the existing 138 kilovolt yard was not sufficient and would need to be replaced with new infrastructure and equipment." There is no technical or engineering analysis that evaluates or explains the need for a new control house or the replacement of additional circuit breakers. Without knowing these details, it is not possible to assess the reasonableness of a $33 million increase from $15.6 million to $48.6 million. Because the $33 million increase has not been adequately justified, it should be removed from the projected plant in-service total.

Q: Do you have any other observations on this project?

A; The financial analysis does not seem to account for the retirement or potential salvage value of the two existing transformers that will be moved to new locations. Reflecting these items would offset some of the capital additions and reduce the test year rate base.

In addition, the delay in the in-service date to December 2012 from May 2012 would also reduce the test year plant in-service and rate base. The test year plant in-service and rate base are based upon the average of 13 months of month-end balances. If a May 2012 in-service date is assumed, the value of the plant installed on that date would be fully reflected in plant in-service as it would be averaged over all 13 months. If a December 2102 in-service date is assumed, the cost of the plant installed on that date would be in the 13-month average for only six months. This would mean that only half of the added plant costs would be included in rates.

Q: What do you recommend?

A: I recommend that the original 2009 cost estimate of $15.6 million be used as the basis for projecting capital additions for the purpose of determining the test year rate base. This figure is what the Company has adequately justified, and is a reasonable cost for the scope. While it may be high due to the omission of the retirement /salvage value for the two existing transformers, it is the most defensible estimate in the documentation that I have. The increase to $48.6 million has not been adequately explained or justified. An in-service date of December 2012 should be used along with the $15.6 million cost estimate.

E. City Creek Center - New 40 MW Development

Q: Please describe the City Creek project.

A: The City Creek project is a new mixed residential and commercial development in downtown Salt Lake City. The project was originally approved internally by the Company in 2007 with an expected in-service date of July 2010. Project costs were $43.7 million, with $36.7 million invested by RMP and $7.0 million paid by PRI, the developer of City Creek, as a Contribution in Aid of Construction ("CIAC"). Over time, the Company has consistently estimated the project's cost at $43.7 million including contingency. The latest documentation provided by the Company indicates a May 2012 in-service date and a $38.16 million cost estimate. The reduced cost is due to the developer constructing certain electric distribution facilities at its expense of $5.55 million, rather than make a cash CIAC payment. Figure 14 below provides a summary of the documentation received for this project.

Figure 14

City Creek Project - Summary of Documentation

Document	Date Prepared	Projects Costs w/o Contingency	CIAC	RMP Costs w/o Contingency	Contingency	Projects Costs w/ Contingency	MW	In-Service Date	Spent To Date
IAD6-phase I	10/2007			$0.15				2/2008	n/a
IAD6-phase II	10/2007			$8.35				10/2009	n/a
IAD6-Phase III	10/2007			$28.20				7/2010	n/a
IAD6-total	10/2007	$43.70	$7.00	$36.70	$0.00	$43.70	28.00	7/2010	n/a
IAD [1]	unknown	$43.70	$7.00	$36.70	$0.00	$43.70	28.00	5/2012	n/a
IAD-ER [1]	1/2008	$40.82	$7.00	$33.82	$3.38	$44.20	28.00	7/2010	n/a
ER	2/2008	$39.33	$7.00	$32.33	$4.37	$43.70	28.00	7/2010	$0.00
PCN	3/2008	$39.33	$7.00	$32.33	$4.37	$43.70	28.00	7/2010	$0.14
PCN-2	8/2009	$39.33	$7.00	$32.33	$4.37	$43.70	40.00	5/2011	$1.04
PCN-3	6/2010	$39.33	$7.00	$32.33	$4.37	$43.70	40.00	5/2012	$8.62
Chg	2/2012	$33.79	$1.46	$32.33	$4.37	$38.16	40.00	5/2012	$21.82
diff from PCN-3 [2]		$5.55	$5.55			$5.55			

[1] Document IAD is very similar to document IAD6 with minor changes. It appears that not all information was updated

[2] Cost of facilities installed by developer in lieu of CIAC

Q: Is this project being built solely for the new City Creek development?

A: No. Based upon the project justification, it appears that the project will also benefit existing customers in this area through the upgrade and /or replacement of antiquated distribution facilities. The project will also provide benefits to future customers who locate in this area through the expansion of additional transmission connections and transformers, according to the Company.

Q: Does RMP have policies to deal with new projects that benefit both new and existing customers?

A: The Company has a line extension policy that is described in Regulation 12. The Company will invest $1,100 to interconnect each new residential customer. The extension allowance for commercial customers is determined by the expected annual revenue. The Company will invest an amount equal to 16 months worth of annual revenue to interconnect each new commercial customer. If the cost to interconnect a new customer exceeds these extension allowances, the customer is asked to make a CIAC to make up the difference. Such a policy is commonplace for electric utilities. These policies maintain equity between existing and new customers, and avoid having the existing customer base support a large investment to add a new customer. According to the Company's response to DPU Data Request 30.16, the Company does not waive the extension allowance. Regulation 12 also provides for refunds of CIAC payments to the originally added new customer if additional customers connect to the line extension on a future date.[7] This provision provides further equity among customers.

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[7] See section 3(c)(2). However, the response to DPU Data Request 31.6 states that future customers will not be assigned a portion of the costs of this project to utilize substation capacity.

Q: Did the Company adhere to this extension policy?

A: In responses to DPU Data Request 31.2, the Company stated that it did not perform an estimate of a CIAC payment for City Creek. However, a $7.0 million payment from the developer is budgeted in the project documentation, indicating that the Company expected PRI to make a CIAC payment. Even when the developer constructed certain distribution facilities at its expense of $5.55 million, it still made a CIAC payment of $1.45 million, bringing the total cash and in-kind contribution to the budgeted amount of $7.0 million. In order to assess if the $7.0 million figure was reasonable, I calculated the estimated CIAC payment using data provided by the Company as shown in Figure 15 below.

Figure 15

ESTIMATE OF CITY CREEK CIAC

Item	Total	PRI	Existing Load	Comment
City Creek Loads, MW	41.8	27.5	14.3	Attach DPU 2 29(2) file City Creek IAD6 pdf
% of total	100%	66%	34%	
Capital Cost, $M				
phase I&II	$9.50	$9.50	$0.00	Attach DPU 2 29(2) file City Creek IAD6.pdf
Phase III	$34.20	$22.60	$11.60	Attach DPU 2 29(2) file City Creek IAD6 pdf
Total	$43.70	$32.10	$11.60	
PRI commercial revenue		$7.82		Response to DPU Data Request 31.1(3) - 05-15-2012 - Attachment.xlsx
Commercial allowance		$10.43		16/12ths of annual revenue per Regulation 12
# Residential units		550		Response to DPU Data Request 31 1(3) - 05-15-2012 - Attachment.xlsx
Residential Allowance		$0.61		$1,100 per unit per Regulation 12
RMP Extension Allowance		$11.04		
PRI Estimated CIAC		$21.06		
PRI Actual CIAC		$7.00		
difference		$14.06		

The original project justification from 2007 stated that the City Creek project would support 27.5 MW of new load and 14.3 MW of existing load. Phases I and II of this project cost $9.5 million. From the description provided, it appeared that the facilities constructed in these phases would benefit the City Creek new load, so I assigned these costs to the developer. I allocated the remaining facilities cost, \$34.2 million, between existing MWs and New MWs on a pro rata load basis. Thus, as shown in Figure 15 above, existing customers should support \$11.6 million and the city Creek Developer should support \$32.1 million. Using load sheet data provided by the Company in the response to DPU Data Request 31.3, the extension allowance is estimated to be \$11.0 million. Thus, in order to comport with Company policy, the City Creek developer should have paid a CIAC payment of \$21.1 million, which exceeds the \$7.0 million actual CIAC payment by \$14.1 million.

Q: What do you recommend to address this differential?

A: Had the Company followed its own procedures and policies, I estimate that the developer of City Creek would have made a CIAC payment of \$21.1 million, which would reduce the amount of this project that is added to plant in-service by \$14.1 million. Therefore, the plant in-service projected for the test year should be reduced by \$14.1 million. If future customers use the facilities constructed under this project and make a payment to the Company that would have been refunded to the developer of City Creek, the Company should retain these revenues, up to the amount of the project assigned to new customers.

Q: Do you have any other observations on the City Creek project as it pertains to the projected plant in-service?

A: On May 21, 2012, the Company provided an update to its capital database with actual investments through March 2012. Figure 16 below compares the monthly investments in both the original and revised databases. The Company adds actual plant additions through March, but does not change the projected entries for May 2012. I think it highly likely that these May entries would change as a result of actual investments through March. Before relying on the revised database, these May entries should be updated.

Figure 16

UTAH CAPEX COMPARISON - ORIGINAL VS. MAY 21ST UPDATE

	Original	Original	Revised	Revised
Month	City Creek Center: New 40 MW Development for PRI Phase II (TRNS)	City Creek Center: New 40 MW Development for PRI Phase II (DIST)	City Creek Center: New 40 MW Development for PRI Phase II (TRNS)	City Creek Center: New 40 MW Development for PRI Phase II (DIST)
Jul-11	7	-	-	-
Aug-11	29,306	-	-	29,257
Sep-11	4,613	-	-	4,613
Oct-11	-	-	-	9,827
Nov-11	-	-	19,862	-
Dec-11	-	-	-	254,106
Jan-12	-	-	4,720	(1,302)
Feb-12	-	-	-	116
Mar-12	-	-	914,175	3,378,465
Apr-12	-	-	-	-
May-12	4,485,383	17,775,267	4,485,383	17,775,267
Jun-12	-	-	-	-
Jul-12	-	-	-	-
Aug-12	-	-	-	-
Sep-12	-	-	-	-
Oct-12	-	-	-	-
Nov-12	-	-	-	-
Dec-12	-	-	-	-
Jan-13	-	-	-	-
Feb-13	-	-	-	-
Mar-13	-	-	-	-
Apr-13	-	-	-	-
May-13	-	-	-	-
sum	4,519,309	17,775,267	5,424,139	21,450,349

F. Skypark 138-12 5kV Substation

Q: Please describe the Skypark 139-12.5kV Substation project.

A: This project involves a new substation which is designed to relieve overloaded transformers in the South Davis County area. RMP projected $8.064 million of plant to be placed in-service in May 2012. It is my understanding that this project has been placed in-service.

Q: Did you identify any concerns with the projection of capital additions associated with this project?

A: Yes. From the documentation and responses to data requests provided by the Company, it appears from the Company's response to DPU Data Request 31.16 that $0.773 million was inadvertently double-counted, and the correct projected amount of plant addition for this project should be $7.291 million. Furthermore, approximately $1.182 million of the projects costs is associated with excess land that is not used as part of this project and has been recorded as non-utility as stated in the response to DPU Data Request 31.14. Therefore, I recommend that the cost of this project in the plant in-service projection be reduced to $6.109 million.

G. Energy West Deer Creek Mine CAP Forecast

Q: Please describe this project.

A: This capital project consists of 21 smaller projects that relate to the on-going advancement of the mine operation. The amount included in the projected test year plant in-service is $8.652 million, with monthly investments over the October 2011 to May

2013 time period. This compares favorably to the estimate of $8.73 million provided in attachment DPU 29.1-1 to the response to DPU Data Request 29.1.

Q: Please summarize your review of this project.

A: In response to DPU Data Request 29.1, the Company provided a list of the projects that make up the larger project in Attachment DPU 29.1-1 and documentation for some of the projects in confidential Attachment DPU 29.1-2. The documentation included APRs for five of the projects including:

- Mainline extension;
- Mainline belt replacement;
- Section extension;
- Belt drive power center; and
- Overland conveyor belt replacement.

The APRs documented $3.277 million in expenses for these five projects. No documentation was provided for the other projects included in Attachment DPU 29.1-1. Figure 17 below shows the 21 projects with the capital expenses included in Attachment DPU 29.1-1 and the expenses documented by the APRs provided by the Company. I recommend including the $3.277 million documented by the Company.

Figure 17

	Company Estimate in Attach DPU 29.1-1	**Cost Documented with APRs in Attach DPU 29.1-2**
Lease Acquisition-New Reserves	70,000	
Coal Reserves-Exploration Drilling	635,000	
Mainline Extension	1,127,000	[redacted]
Mainline Belt Replacement	546,000	[redacted]
Mainline Ventilation Seals	684,000	
Section Extension	1,196,600	[redacted]
48" Terminal Group	524,000	
Mine Monitoring/UG Communication	225,000	
Triple Sectionalizing Switch	145,000	
UG Forklift	75,000	
UG Personnel Carrier-Specialty Vehicles	109,000	
Surface Facilities Improvements	150,000	
Intermediate Loading Section	50,000	
Belt Drive Power Center	380,000	[redacted]
Overland Conveyor Belt Replacement	1,148,000	[redacted]
Overland Conveyor-C1/C2 Drive & Brake	300,000	
Belt De-watering System	480,000	
I/T Equipment Replacement	122,000	
Safety-Personal Dust Monitors	260,000	
Safety-Handheld Monitors	230,000	
Items < $100k	266,000	
Total Energy West Deer Creek Mine CAP Forecast	**8,722,600**	**3,277,000**

H. Scipio Pass - Mineral Mountain Microwave

Q: Please describe this project.

A: According to the response to DPU Data Request 26.6, the Scipio Pass - Mineral Mountain Microwave project replaces an existing analog microwave that is obsolete and is a bottleneck to providing digital communications services for power grid operations, security, and administrative services. The Company asserts that this equipment is in need of replacement due to obsolescence in functionality, lack of compatibility with new devices, poor reliability, and increasing maintenance costs. Furthermore, RMP claims that some failed equipment will be unable to be repaired due to discontinued product lines, which could cause adverse consequences to the Company. The projected capital investment is estimated by the Company to be $2.780 million with an in-service date of December 2011.

Q: What did your review of this project indicate?

A: The APR for this project and the accompanying Executive Report and Authorization documentation states that the approved budget for this project is $1.480 million, not the $2.780 million reflected in the filing. Therefore, the projected capital spending for this project should be reduced to $1.480 million. I note that actual spending through March 2012 for this project is $1.3 million, which is consistent with the above change in the Company's test year plant in-service forecast.

I. 2GHz Microwave Replacement

Q: Please describe this project.

A: This project involves the replacement of the analog microwave and analog multiplexing equipment at Pavant and Delta Service Center with digital channel banks. The Richfield Service Center will have a digital channel bank installation required. According to RMP, if the 2 GHz frequencies are not replaced or turned off by the end of the year, the FCC, as mandated, will categorize the Company's frequencies as secondary, which would interfere with its communications system. The Company included $0.350 million in the projected plant in-service estimate with a December 2012 in-service date.

Q: What did your review of this project indicate?

A: The documentation provided by the Company consisted of a two-page APR, which showed an approved budget of $0.134 million for fiscal year 2013. This document was created on April 12, 2012. In response to DPU Data Request 26.8, the Company stated that this project has not been subject to competitive bidding, as it is in "it's very early evaluation stages". Based upon this documentation, the amount included in test year plant in-service should be reduced to $0.134 million from $0.350 million.

J. Other Adjustments

Q: Please describe the remaining adjustments that you made.

A: There were several projects for which no or inadequate documentation was provided. These are the (1) JB U2 Replace Cooling Tower 12/13, (2) Naughton U0 BART Study for CAM, (3) Currant Crk U2 CSA Variable fee 24k - CTB M, (4) Cholla U4 FABRIC FILTER BAG REPLACE CY13, (5) Hermiston U0 Auxiliary Boiler, (6) Naughton U0 D10 Replacement, and (7) W-1799 Replace three generators company wide. Because of lack of adequate documentation, these projects should be removed from the plant in-service projections.

XI. Additional Documentation

Q: In your review of the Company's projection of plant in-service, you identified certain situations where inadequate documentation has been provided. Is it possible that additional documentation may be provided by the Company?

A: Yes, it is possible that additional documentation could be located and provided by the Company.

Q: How do you recommend that such additional documentation be dealt with?

A: I believe that it would be reasonable to consider such additional documentation, so long as that documentation existed as of the date of the Company's filing in this proceeding. In providing such additional documentation, the Company should demonstrate that it existed as of the filing date.

XII. Interpretation of Sample Results

Q: Your evaluation of the Company's projected plant additions is based upon a review of certain specific projects in a sample, rather than examining every proposed project. Can the sample results be extrapolated to the entire database of projects?

A: I have treated each project as a unique investment, and have reviewed the specific documentation provided. My analysis was based upon each individual project. However, the selection of projects was based upon a stratified random sample, and the evaluation looked at a wide range of projects of all sizes across all Company functions. I believe that this approach results in a reasonably representative sample. I reviewed 45 specific projects with total plant additions of $258 million. I recommend changes in 15 of these projects, resulting in a reduction of $92.4 million. As a result of the recent decision to convert Naughton Unit 3 to burn natural gas instead of coal, I reviewed an additional 8 projects with total plant additions of $1.78 million. I recommend changes in 6 of these projects, resulting in $1.3 million in reductions. I reviewed 53 generic projects totaling $243 million, and recommend changes in 9 of these totaling $34 million.

It might be tempting to attempt to extrapolate the results of the review of the sample of projects to the entire database of proposed plant additions. I stop short of making such a recommendation, because each project is unique and such an extrapolation might not be statistically valid. However, I do believe that the Commission should consider the possibility that, if I had examined a greater number of projects, additional reductions in projected plant in-service could be identified. The suggested changes in this testimony should therefore be considered as conservative.

XIII. Conclusion

Q: Does this conclude your testimony?

A: At this time, yes, it does. Should additional or new information become available, I will supplement this testimony as appropriate.