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. 13-035-184** **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

May 1, 2014

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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 Utah Division of Public Utilities (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 Exhibit DPU 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 the same capacity in the previous Rocky Mountain Power general rate case, Docket No. 11-035-200. 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. 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. I have also provided testimony in the last two RMP energy balancing account reviews, Docket Nos. 12-035-67 and 13-035-32.

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 projects. In some cases, adequate documentation has not been provided or the Company has acknowledged that such documentation does not yet exist.
- The Company's filing projects plant additions (before netting retirements) from July 2013 through June 2015 to be $2,578 million. The test year plant in-service is based upon the thirteen-month average from June 2014 through June 2015. From July 2013 through May 2014, projected plant additions are approximately $676 million, and $1,902 million is projected to be added from June 2014 through June 2015.[1]
- Since its January filing, the Company has provided updated information based on actual expenditures through February 2014 and revised forecasts for March 2014 to June 2015. DPU staff's analysis of the updated information shows a revised forecast of $2,542 million in plant additions over the 24 month period.

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[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.

- Some proposed projects have currently expected in-service dates that are different than the in-service dates included in the Company's projected plant additions.
- I have serious concerns about the Company's process for budgeting and accounting for generic projects, which account for more than 20% of the forecast additions to plant in service.
- Based upon my review of the original filing, I find that several adjustments to the Company's proposed capital spending from July 2013 to June 2015 should be made. Specifically, I recommend that the $2,578 million in capital spending proposed by the Company be reduced by $442 million due to adjustments to 11 projects. The impact on the 13-month test period average addition to plant is $45 million, and Utah's share of this reduction is about $22 million. Figure 1 below summarizes the adjustments to the Company's proposed capital spending for the July 2013 to June 2015 period related to my sample review.
- Subsequent to its filing in this case, the Company has removed 20 projects from its forecast of additions to plant in-service before or during the test period. These projects, which contributed a total of $58 million to the originally-proposed capital additions, should also be removed from rate base.
- Subsequent to its filing in this case, the Company proposed 10 new projects forecast to be in-service between March 2014 and June 2015, with total capital spending of $25.9 million. The Company failed to provide adequate documentation showing need or internal approval for these projects, and so they should not be allowed in rate base.

- Division staff has estimated the effect on revenue requirements of adjusting projected plant additions as recommended in my testimony. DPU updates based on actual plant additions and other actuals through February 2014 and changes in the Company's forecast of future plant additions increase Utah revenue requirements by $0.232 million. My recommended adjustments to the 11 projects, as described in Section X of my testimony, has the effect of reducing Utah revenue requirements by $2.664 million relative to the DPU-adjusted amount. Disallowing the addition of the 10 newly-proposed projects, as described in Section XII of my testimony, has the effect of reducing Utah revenue requirements by $0.683 million relative to the DPU-adjusted amount. The net effect of these changes is to reduce the revenue requirement by $3.3 million relative to the DPU-adjusted amount. This change is described further in Exhibit DPU 5.0 Dir-Rev Req, the testimony of Matthew Croft on behalf of the Division.
- The Company failed to follow its own policies and procedures with regard to collecting contribution in aid of construction (CIAC) payments associated with the City Creek project, which was completed and placed into service prior to July 2013. The $10.85 million shortfall in CIAC payment collection should be removed from plant in-service in this case. Division staff has estimated that such a removal would reduce the revenue requirement by $1.3 million.

Figure 1

La Capra Associates Proposed Adjustments to Sample of RMP Forecasted Plant Additions

		RMP Filing per DPU 4.1					LCA Proposed Adjustments					
Project	Function	Factor	In-Service	July13 to Jun15 Plant Adds	Test Period 13 Month Avg. Plant Adds	UT Share - 13-mo Avg. Plant Adds	Factor	In-Service	July13 to Jun15 Plant Adds	Test Period 13 Month Avg. Plant Adds	UT Share - 13-mo Avg. Plant Adds	Change to UT Share 13-mo
FC200 to FC300 Replacement (Obsolescence)	GNLP	SG	Dec-13	1,127,016	1,127,016	480,428	UT	Dec-13	279,160	279,160	279,160	(201,268)
MILL FORK SOUTH LEASE ACQUISITION	MNGP	SE	Various	5,121,701	3,484,598	1,462,546	SE	Unknown	-	-	-	(1,462,546)
Casper Outer Loop - New 115kV Red Butte to WAPA	TRNP	SG	Jun-15	6,510,504	500,808	213,486	SG	Jun-15	267,000	20,538	8,755	(204,731)
Sigurd - Red Butte 345 kV line	TRNP	SG	Jun-15	363,731,733	27,979,364	11,927,132	SG	post-Jun15	-	-	-	(11,927,132)
West Point: New 138 kV Line & 40 MVA Substation	TRNP	SG	Apr-15	6,639,843	1,524,847	650,017	SG	post-Jun15	-	-	-	(650,017)
West Point: New 138 kV Line & 40 MVA Substation	DSTP	UT	Apr-15	8,758,441	2,002,422	2,002,422	UT	post-Jun15	-	-	-	(2,002,422)
Whetstone 230-115KV Substation phase 1 - TPL002	TRNP	SG	Jun-15	17,746,272	1,365,098	581,918	SG	post-Jun15	-	-	-	(581,918)
N1--N1--New Revenue/Connection - Residential	DSTP	UT	Various	46,374,853	33,850,979	33,850,979	UT	Various	41,247,063	30,742,347	30,742,347	(3,108,632)
Hydro Vehicles 2015	GNLP	SG	Jun-15	674,269	51,867	22,110	SG	Jun-15	377,239	29,018	12,370	(9,740)
VEHICLE REPLACEMENT	GNLP	SE	Jul-14	40,000	36,923	15,497	SE	Jul-14	-	-	-	(15,497)
EMS/SCADA Replacement / Upgrade (combined)	INTP/GNLP	SO	May-15	27,813,671	4,279,026	1,817,315	SO	post-Jun15	-	-	-	(1,817,315)
Bigfork Penstock 3 Headgate Upgrade	HYDP	SG-P	Oct-14	93,448	64,695	27,578	SG-P	Jul-05	-	-	-	(27,578)
Subtotal				484,631,752	76,267,642	53,051,428			42,170,462	31,071,064	31,042,632	(22,008,796)
Removed from Forecast by RMP*				33,946,877	10,244,280	4,366,964			-	-	-	(4,366,964)
Remaining Projects in LCA Sample				294,784,267	254,378,737	126,914,318			294,784,267	254,378,737	126,914,318	-
LCA Sample TOTALS:				**813,362,896**	**340,890,659**	**184,332,710**			**336,954,730**	**285,449,800**	**157,956,950**	**(26,375,760)**

** Per response to DPU 35.4. See Figure 14 for a list of these projects that were in the LCA sample. Adjustments related to other removed projects are made in DPU Staff Testimony.*

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 June 2014 to June 2015. At the time the filing was prepared, it is my understanding that the Company had actual plant in-service data as of June 30, 2013. The Company projected net plant additions by month over the 24 month period from July 2013 through June 2015. 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 24 months using historical distributions. Because these generic projects represent an aggregation of many smaller capital investments, the assumption of monthly closings to plant-in-service is intended to simulate what will actually occur. 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's January filing includes a forecast of $2,681 million in new capital projects between July 2013 and June 2015. There are 1,885 individually identified projects that sum to this total. Figure 2 below provides a summary of the Company's proposed additions during this 24 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

13-035-184 SUMMARY OF PROJECTED CAPITAL EXPENDITURES
July 2013 to June 2015

Sum of Costs ($Millions)		Generic				Specific				
Account	Category	>$5M	$5M to $1M	<$1M	Total	>$5M	$5M to $1M	<$1M	Total	Grand Total
302-303	Intangible Plant	14.27	3.57	0.51	18.35	19.90	7.96	4.10	31.96	50.32
312	Steam Plant	0	0	0	0	209.10	80.32	117.83	407.25	407.25
332	Hydro Plant	0	0	0	0	58.80	32.21	27.21	118.22	118.22
343	Other Plant	0	0	0	0	737.84	8.95	20.60	767.40	767.40
355	Transmission Plant	60.84	36.99	21.50	119.33	578.31	59.01	14.50	651.81	771.15
360-373	Distribution Plant	228.76	101.06	37.88	367.70	21.45	13.52	9.09	44.06	411.76
397	General Plant	30.90	22.10	11.34	64.34	15.20	35.08	13.97	64.24	128.59
399	Mining Plant	0	0	0	0	5.12	11.02	10.48	26.62	26.62
Grand Total		334.77	163.72	71.24	569.73	1,645.71	248.07	217.77	2,111.56	2,681.29

Number of Projects		Generic				Specific				
Account		>$5M	$5M to $1M	<$1M	Total	>$5M	$5M to $1M	<$1M	Total	Grand Total
302-303	Intangible Plant	1	1	2	4	1	3	30	34	38
312	Steam Plant	0	0	0	0	12	41	749	802	802
332	Hydro Plant	0	0	0	0	1	15	183	199	199
343	Other Plant	0	0	0	0	7	4	134	145	145
355	Transmission Plant	6	19	95	120	18	24	36	78	198
360-373	Distribution Plant	21	46	126	193	3	4	22	29	222
397	General Plant	3	12	49	64	2	14	154	170	234
399	Mining Plant	0	0	0	0	1	7	39	47	47
Grand Total		31	78	272	381	45	112	1,347	1,504	1,885

Forecast plant additions are $2,681 million minus $103 million in “Five Year Average Removals” which equals $2,578M in plant additions (see Figure 3).

Figure 3

13-035-184 5 YEAR AVERAGE REMOVALS
July 2013 to June 2015

Sum of Costs ($Millions)		[1]	[2]	
Account	**Category**	**Capital Projects Database**	**5 Year Avg Removals**	**Plant Additions**
302-303	Intangible Plant	50.3	0.0	50.3
312	Steam Plant	407.3	(41.7)	365.5
332	Hydro Plant	118.2	(2.7)	115.5
343	Other Plant	767.4	(2.2)	765.2
355	Transmission Plant	771.1	(11.7)	759.4
360-373	Distribution Plant	411.8	(42.8)	369.0
397	General Plant	128.6	(1.9)	126.7
399	Mining Plant	26.6	(0.1)	26.5
Grand Total		2,681.3	(103.1)	2,578.2

Notes:
[1] Response to DPU 4.1
[2] SRM-3, 8.6.21-8.6.23

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 $2,578 million over two years equates to annual additions to plant in-service of about $1,289 million. Since being acquired by Mid-American Energy in early 2006, the Company has invested on average $1,598 million per year in new plant, with

$1,214 million added in 2012. Figure 4 below provides this historic data based on the Company's annual FERC Form 1 reports.

Figure 4

PacifiCorp Plant Additions 2006 through 2012
($millions)

Plant Category	2006	2007	2008	2009	2010	2011	2012	2006-12 Avg
distribution	$239	$283	$282	$257	$222	$243	$209	$248
general	$81	$72	$75	$76	$89	$131	$87	$87
hydro	$15	$19	$43	$57	$32	$80	$161	$58
intangible	$34	$18	$81	$33	$101	$51	$27	$49
other prod	$360	$586	$780	$588	$252	$27	$36	$376
steam	$322	$186	$331	$273	$687	$614	$445	$408
transmission	$121	$184	$217	$291	$1,030	$204	$248	$328
net adjustments	($0)	$0	$303	$3	$2	($1)	$0	$44
total	$1,172	$1,346	$2,111	$1,578	$2,416	$1,350	$1,214	$1,598

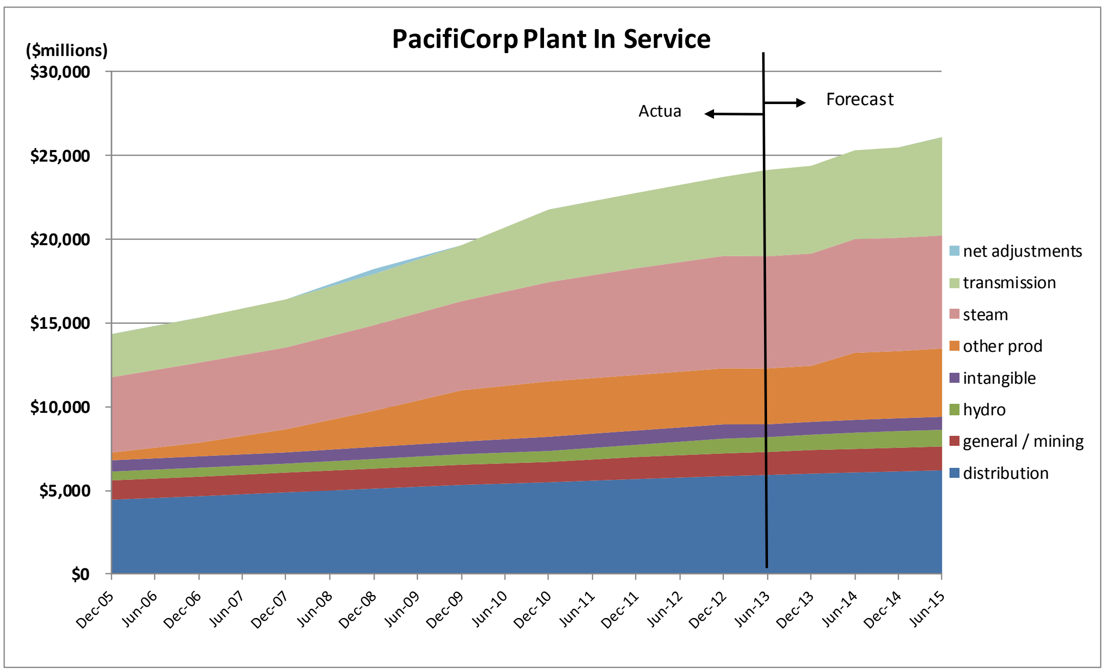
The Company projects retirements of about $616 million from July 2013 through June 2015, resulting in net plant added of $1,962 million ($2,578 million in new capital investments less $616 million in retirements). Thus, plant in-service from July 2013 through June 2015 increases by $1,962 million to $26,106 million from $24,144 million. Figure 5 below shows plant in-service balances from 2005 through the test year projection in this case. From 2005 through 2012, plant in-service increased at a compound annual growth rate (CAGR) of 7.5% from $14,336 million to $23,734 million. From July 2013 to June 2015 plant in-service is forecast to increase at a CAGR of 4.0%.

Figure 5

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

	[1]	[1]	[1]	[1]	[1]	[1]	[1]	[1]	[2]	[2]	[2]	[2]	[2]
Plant Category	**Dec-05**	**Dec-06**	**Dec-07**	**Dec-08**	**Dec-09**	**Dec-10**	**Dec-11**	**Dec-12**	**Jun-13**	**Dec-13**	**Jun-14**	**Dec-14**	**Jun-15**
distribution	$4,446	$4,653	$4,885	$5,106	$5,329	$5,487	$5,679	$5,853	$5,921	$6,002	$6,070	$6,137	$6,203
general / mining	$1,152	$1,164	$1,182	$1,197	$1,206	$1,214	$1,317	$1,359	$1,374	$1,411	$1,407	$1,415	$1,423
hydro	$528	$540	$534	$575	$628	$657	$728	$881	$885	$915	$972	$995	$993
intangible	$672	$678	$671	$721	$752	$848	$853	$854	$769	$767	$765	$765	$781
other prod	$457	$811	$1,383	$2,157	$3,060	$3,308	$3,320	$3,341	$3,334	$3,348	$4,006	$4,012	$4,076
steam	$4,502	$4,782	$4,888	$5,111	$5,325	$5,927	$6,373	$6,720	$6,703	$6,705	$6,788	$6,771	$6,751
transmission	$2,578	$2,689	$2,875	$3,055	$3,343	$4,339	$4,500	$4,725	$5,156	$5,246	$5,309	$5,397	$5,879
net adjustments	$0	$0	$0	$303	$3	($4)	($1)	$0	$0	$0	$0	$0	$0
Grand Total	$14,336	$15,317	$16,417	$18,225	$19,646	$21,776	$22,770	$23,734	$24,144	$24,394	$25,318	$25,492	$26,106
Annual Increase		6.8%	7.2%	11.0%	7.8%	10.8%	4.6%	4.2%		2.8%		4.5%	

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



Q: Have the proposed plant in-service additions changed since the Company filed its case in January?

A: Yes, as new information has become available the Company has provided updates to its capital spending forecast in response to data requests. The updates include the following:

1) The Company has provided actual monthly plant in-service figures by function through February 2014, as well as project-specific actual figures for projects greater than $1 million[2];

2) The Company has identified 20 projects representing a total of $57.8 million in proposed additions to plant in-service that have either been cancelled or delayed beyond the test period[3];

3) The Company has proposed an additional 10 projects representing $25.9 million that were not in the filing but are now forecast to be in-service between March 2014 and the end of the test period in June 2015[4]; and

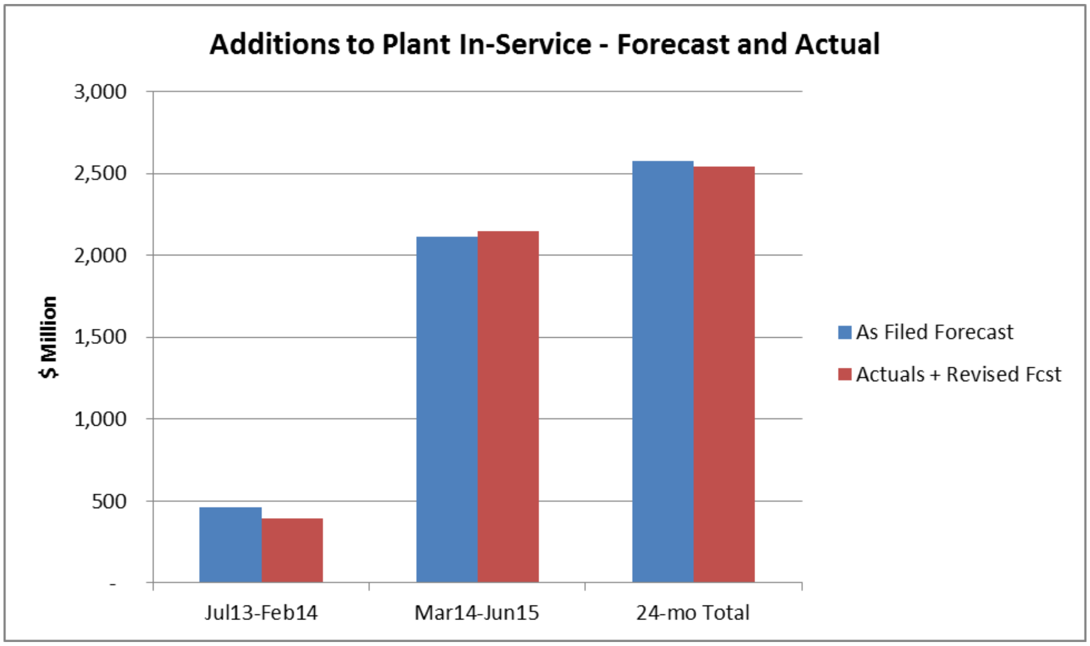
4) The Company has revised the timing and spending amount from 11 projects representing a total of $90.0 million in plant in-service additions (revised to $87.9 million)[5].

The net impact of these revisions is to reduce the projected July 2013 to June 2015 additions to plant in-service from $2,578 million to $2,542 million. The figure below shows how the as-filed forecast compares to actual plant additions in the 8-month period

[2] RMP Response to Data Request DPU 8.1
[3] RMP Response to Data Request DPU 35.1
[4] RMP Response to Data Request DPU 35.4
[5] RMP Response to Data Requests DPU 35.2 and 35.3

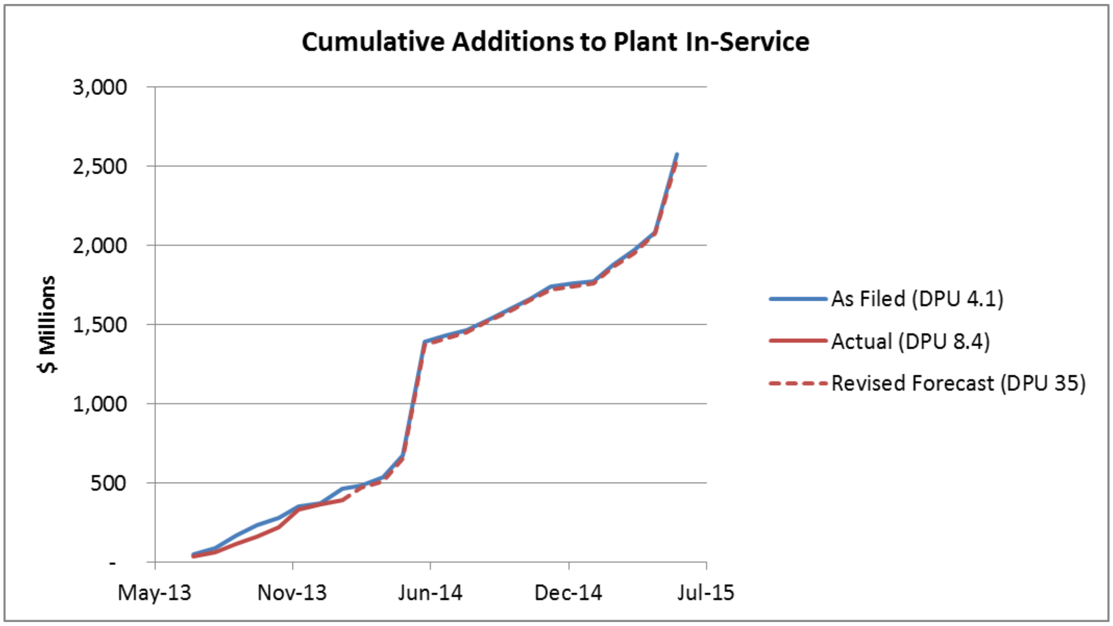
from July 2013 to February 2014, and the revised forecast for the remaining 16-month period from March 2014 to June 2015.

Figure 6



The cumulative additions to electric plant in-service are shown graphically in the figure below:

Figure 7



Q: Do you recommend adjusting the Company's forecast of plant in-service based on these actual spending and revised forecasts?

A: Yes, with certain project-specific exceptions detailed later in my testimony, it is appropriate to update the Company's filed figures based on new information that has become available.

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 Request 9.2 asked the Company to provide copies of all internal documentation describing the procedures or protocols for internal approval of capital projects, including any criteria, such as benefit/cost analyses that are required to support such approval. In its response the Company provided a document titled "Corporate Governance and Approvals Process."

Q: What information about project approvals is provided in the Corporate Governance and Approvals Process policy document?

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. The policy explicitly states: "Inclusion of a project in the approved budget/10-year plan does not constitute project approval; specific project approval must be obtained and documented in accordance with this policy."[6]

[6] Attachment DPU 9.2 at 5.

Q: What policies regarding documentation of capital expenditure projects is provided in the Corporate Governance and Approvals Process policy document?

A: Section 3.1 of this document describes the guiding principles and policies for capital expenditures that will be followed by the Company. The overview states, "The key consideration is to ensure that projects provide clear, *documented* customer benefits in order to maximize regulatory recovery of costs and earnings on investment (emphasis added)."[7] There are numerous prescriptions within the document with respect to required approvals and documentation for projects. In particular, section 3.3 states that "a standard proposal package, including financial modeling results, will be prepared for capital projects $1 million and above…"[8]

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, as well as facilitating regulatory oversight. 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

[7] Attachment DPU 9.2, at 5.
[8] Attachment DPU 9.2, at 8.

such documentation would be prepared prior to the development of project proposals, and that such documentation would be reviewed prior to approval of the project.

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 4.1, details were provided on 1,885 individual capital projects ("Capital database", provided as Exhibit DPU 3.2 Dir-Rev Req). As shown in Figure 2 above, I have classified 381 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 or a Work Breakdown Service (WBS) number. So, the 381 projects listed in the capital database that did not have an assigned WBS or 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 381 generic capital projects shown in Figure 2 did you examine in further detail?

A: It would not be practical to examine all 381 projects in detail. I created a sample of 34 generic projects to examine in more detail. I did not include in this sample any generic projects that 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. The sample list of generic projects was developed by first examining the brief description provided by the Company and selecting those projects with obvious questions. I also included some projects that were reviewed in the prior rate case, but were not resolved by the Commission. The balance of the sample was randomly chosen.

Of the 34 projects reviewed, 25 projects were associated with transmission plant, six were associated with distribution plant, two were associated with intangible plant, and one was associated with general plant. Figure 6 below provides a summary of the generic projects analyzed. The total cost of the 34 projects reviewed is about $160 million, or roughly a quarter of the $570 million total for all generic projects in the Company's Capital Database. Exhibit DPU 3.3 Dir-Rev Req provides a listing of the individual generic capital projects analyzed.

Figure 8

GENERIC PROJECTS ANALYZED

Plant Type	Count	Projected Plant Additions ($000s)
Intangible	2	$17,843
Transmission	25	$33,024
Distribution	6	$90,684
General	1	$18,572
Grand Total	34	$160,122

VIII. Analysis of Generic Projects

Q: Please explain your methodology for analyzing 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 historical data and spending trends and combine that analysis with any additional explanation provided by the Company in responses to data requests.

Q: Have you used this methodology in the past?

A: Yes, I used the same basic methodology to evaluate generic projects in my Direct Testimony in the prior general rate case (Docket No. 11-035-200).

Q: What information did you seek from the Company to complete your analysis?

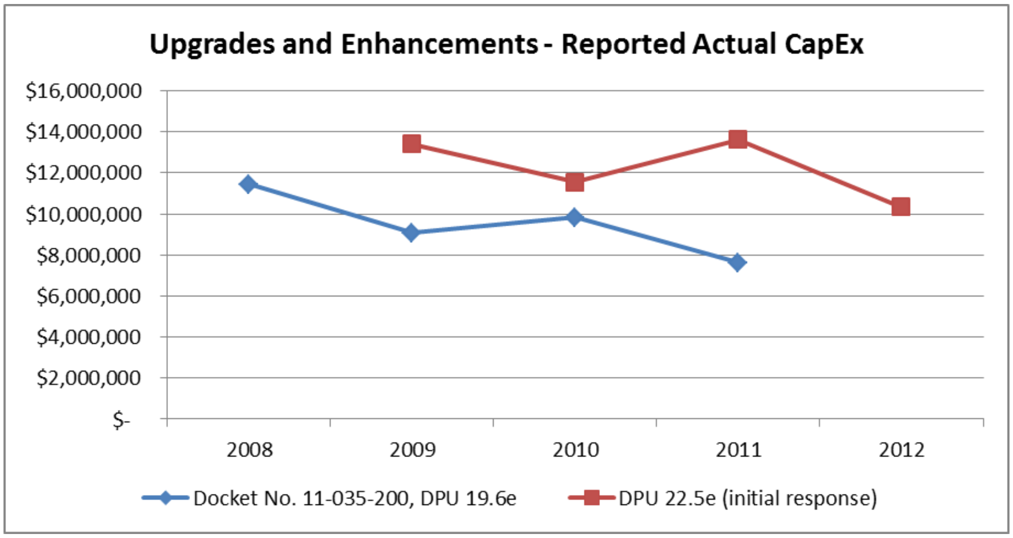
A: In Data Request DPU 22.5, the Company was asked to provide for each of the 34 generic projects in my sample:

1) An explanation of the difference between multiple projects with the same name;
2) An explanation of the Company's method of establishing projected capital spending amounts;
3) An explanation of any adjustments to reflect changes in economic conditions;
4) Budgeted and actual capital expenditures for the years 2008-2013;
5) Documentation of the reason for any significant variance between budgeted and actual spending.

Q: How would you characterize the Company's response to the data request?

A: The Company's initial response to the data request was incomplete. It did not address all the projects in the sample, and the documents that were provided did not contain the level of detail necessary to review the Company's forecasts. More complete responses were eventually provided in response to follow-up requests. However, I came to have serious concerns about the accuracy of the data provided. Some of the projects in my sample happened to be in my sample in the last rate case (Docket No. 11-035-200) as well. Since the data request explicitly requested historical capital expenditure data in the same format that it was provided in that case (for the years 2006-2011), I was able to compare actual data for the overlapping years of 2008-2011. I found that the actual historical data for some years was different in this case compared to the last rate case, and in many cases the disparity was quite significant. The figure below shows an example of one project, Upgrades and Enhancements.

Figure 9



Q: What was the Company's explanation for the disparity?

A: A conference call was held with Company representatives and DPU staff on April 14, 2014 to discuss the issues I identified with the generic projects data. Prior to the call, the Company provided a 4th Supplemental response to DPU 22.5 with revised data for several projects that corrected a double-counting mistake in the original response. This revised data appeared to be consistent with data received in the last case. However, during the course of the phone call, I became aware of several facts that decreased my confidence that I can perform an effective review of these generic projects based on the information the Company is able to provide.

Q: What concerns do you have?

A: One clarification that was offered is that four projects in the capital database -- Total Obsolescence Management (TOM), Upgrades and Enhancements, Corp Optimization, and IT Updates – are all tracked within a single category of IT Management. Actual or planned IT expenditures are not assigned to an individual project code, so any numbers provided for these projects are subject to the judgment of an analyst tasked with providing the response. It appears that different analysts performed this disaggregation in this case and the previous case. Furthermore, the Company clarified that "reason codes" for other generic projects are periodically changed, and the changed codes are applied retroactively to past expenditures. However, the Company keeps no records of when and how such accounting changes are made.

While the designation of individual expenditures to generic project categories or "reason codes" is not always precise and requires some measure of subjective decision-making, I see no reason for the Company's failure to maintain a stable and transparent accounting of these decisions. It is very difficult, if not impossible, to review the capital budgeting and expenditure decisions made by the Company if the underlying actual historical data is inconsistent and subject to retroactive revision.

Q: What do you recommend with regard to the Company's process for forecasting generic project budgets?

A: The Company is forecasting almost $600 million in additions to plant in service for generic projects, or more than 20% of total forecasted capital additions. Though individual expenditures tend to be smaller, they add up to a significant portion of the capital budget. It appears to me that the Company does not have a consistent and transparent methodology for recording actual historical data and making projections, and it certainly hasn't documented its forecasting process satisfactorily. I recommend that the Commission direct the Company to address these issues and improve the generic project budgeting process in more detail to assure more effective oversight before— and in conjunction with—filing its next rate case.

Q: Have you reviewed the revised data for the sample generic projects?

A: Yes, I have. Setting aside for the moment my underlying concerns about the data itself, I still analyzed the final revised data provided according to the methodology I described earlier. First I analyzed spending and budgeting trends to determine if the Company's proposed additions are in line with recent history. In any cases when the proposed spending was out of line with recent trends, I reviewed 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.[9]

Q: Please describe your analysis of the N1–New Revenue/Connection – Residential (UT) project.

A: This project represents the costs incurred to connect new residential customers in Utah to the RMP system. It is logical to treat this as a generic project because it consists of more than 1,000 individual connection projects each year. The Company forecasts $46.4

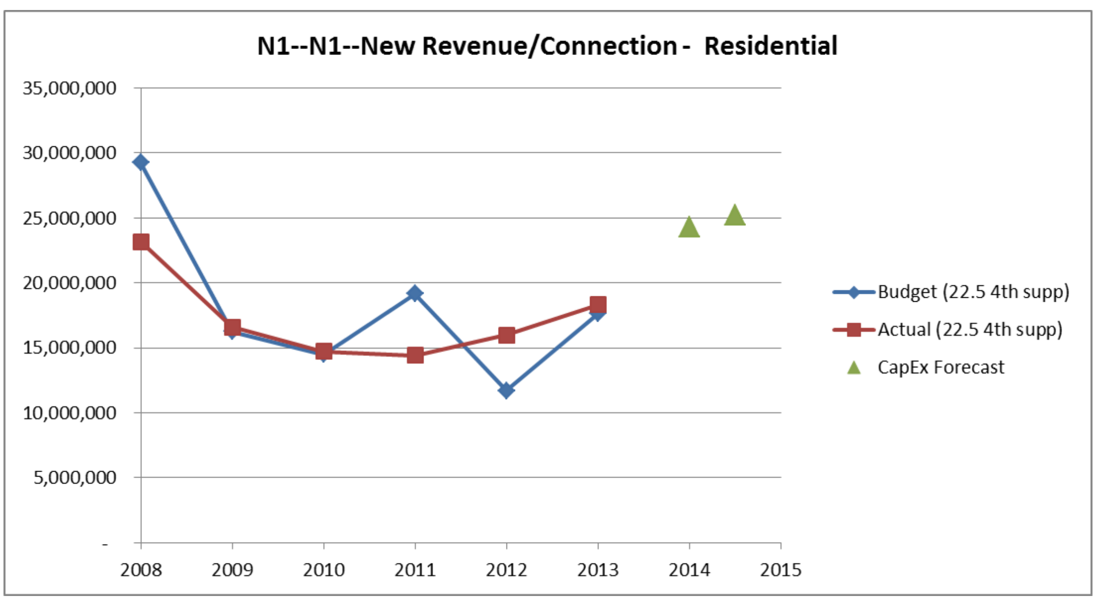
[9] See response to Data Request DPU 22.5b.

million added to plant in-service between July 2013 and June 2015. The forecast is based on the customer forecast used in the Company's load forecast multiplied by a flat per connection cost.[10]

Q: Do the capital expenditures for this project appear to line up with historical trends?

A: Though actual expenditures in this category have been rising since 2011, it appeared to me that the projected spending was significantly above even the trend in the past few years. The figure below shows data provided by the Company for both actual spending (red line with square markers) and budgeted amounts (blue line with diamond markers) through 2013. The green triangles represent the proposed spending for 2014 and the 12 month period ending in June 2015.

Figure 10



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10 See response to Data Request DPU 22.7.

Q: Has the Company provided documentation sufficient to support this step increase?

A: No. Given the formula for producing the budget, the increase must be a result of either an increase in the number of customers or an increase in per unit cost (or both) above recent trends. The Company has provided no evidence that the per unit cost of connections has risen materially. According to Company Witness Kelcey Brown, "the Company forecasts the number of customers using IHS Global Insight's forecast of number of households and population as the demographic driver."[11] The confidential figure below shows the IHS Global Insight forecast of incremental household growth in Utah used in the load forecast (red line with square markers).[12] The blue line with diamond markers shows actual spending on new residential connections for the past six years. The trend for new household growth is [redacted]. I see no evidence here to justify such a marked increase above spending trends as proposed by the Company for this project category. I recommend an adjusted forecast that maintains the historic spending trend from 2011 to 2013 into 2014 and 2015 (see purple dashed line in figure below).

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11 Prefiled Direct Testimony of Kelcey Brown, lines 183-184.
12 Response to Data Request DPU 10.15.

Confidential Figure 11

[redacted]

This adjustment results in higher plant additions in 2013 (in line with actual) and lower additions in 2014 and 2015. I used the Company's monthly spending distribution numbers to develop monthly figures for the test period. The resulting 24 month total additions to EPIS total $39.7 million, or an 11% reduction from the Company's proposed $46.4 million. The impact of this adjustment is described in Exhibit DPU 5.0, staff's direct testimony in this proceeding.

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

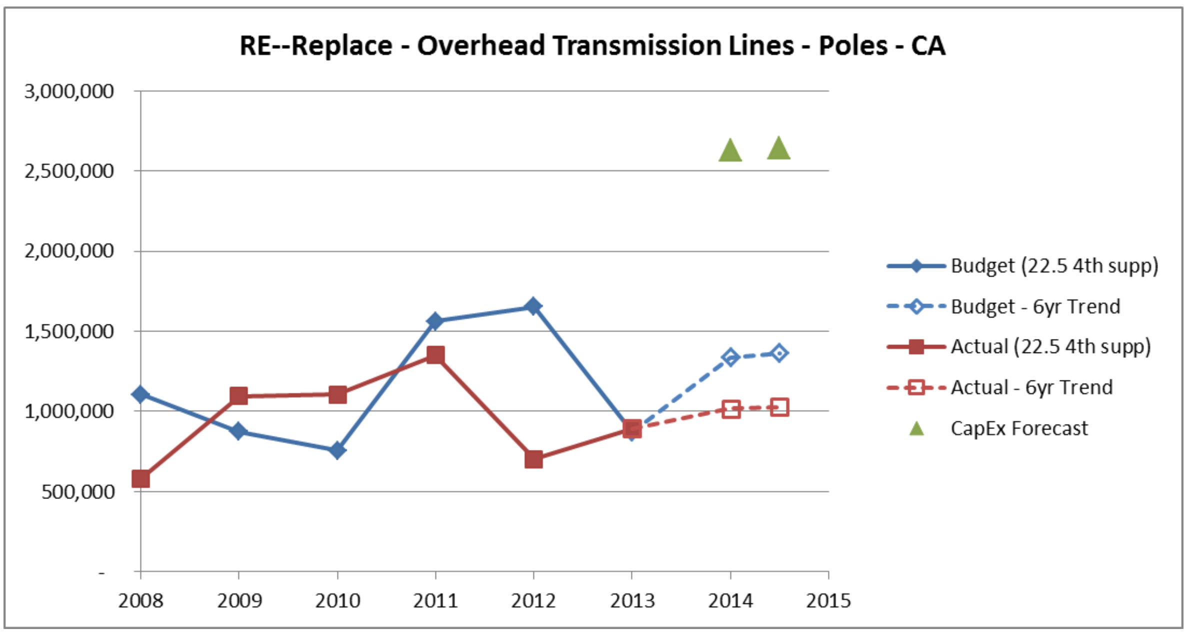
A: No. Through discovery, the Company was provided the opportunity to explain any variance between their projected expenditures and historic spending trend. In other cases

I found their explanations sufficient. Therefore, I am not recommending adjustments to any other generic projects at this time.

Q: Did any other generic projects raise concerns?

A: In the course of my review I did determine that the "RE – Replace - Overhead Transmission Lines – Poles" capital expenditures forecast appeared to be above historic trends. Upon more detailed review, I determined that this increase was largely due to a large projected increase in spending in California, as shown in the figure below.

Figure 12



Q: Did the Company offer any explanation for these numbers?

A: In one of the workpapers supplied as documentation for this project, the Company included the following note: "*Oregon and California projections included the regulatory* *requirements for pole replacements. To reduce a steep increase in pole replacements in CY16 in California, some of the regulatory required poles were brought into CY15. Starting after CY16, the number of pole replacements in each state is escalated year on year to correspond with pole deterioration.*"[13] The Company did not provide copies of, or citations to, the stated regulatory requirements that are claimed to be the driver behind such a large increase. Based on some high level research, it appears that the California PUC did revise its guidelines for constructing and maintaining utility poles in January 2012. However, I cannot establish a direct link between these revisions and the Company's projections of capital spending in this area.

Q: What is your recommendation regarding this project?

A: The Company should provide the new regulations that are causing the increase in capital spending and show in detail how these new regulations were used to derive the forecast. Assuming that the Company provides this information and the information justifies the forecast, I would accept the increased capital expenditure forecast as being reasonable.

IX. Selection of Specific Projects Reviewed

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

A: Of the $2.7 billion in capital expenditures forecast by the Company from July 2013 to June 2015, more than $2.1 billion is budgeted for 1,504 specific projects. In contrast to

[13] Response to Data Request DPU 22.5, "RE PP Budget Worksheet_KA.xlsx"

"generic" projects, these line items contain projected expenditures for discrete projects that will be completed and placed in-service on a specific date by June 2015. 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 49 projects to review in some detail. Figure 13 below provides a summary of the specific projects analyzed. Exhibit DPU 3.4 Dir-Rev Req provides the full list of the specific projects that I reviewed.

Figure 13

SPECIFIC PROJECTS ANALYZED

Account	Plant Type	Count	Projected Plant Additions ($000s)
302-303	Intangible	1	$19,900
312	Steam Plant	24	$141,824
332	Hydro Plant	4	$59,016
343	Other Plant	5	$3,109
355	Transmission	6	$402,955
360-373	Distribution	1	$8,758
397	General	5	$9,782
399	Mining Plant	3	$7,896
Grand Total	Grand Total	49	$653,241

Q: How was the sample chosen?

A: Two projects were included in my sample at DPU's request. The two projects are (1) Blundell Proj Dev and Well Integration; and (2) Populus - Terminal 345 kV line -

condemnation settlements. Ten projects were selected based on previous experience with the projects or similar projects in the previous rate case. Twelve projects were added to the sample because they were scheduled for in-service dates of June 2015, at the very end of the test period. For these projects, I wanted to determine if that scheduled in-service date was still reasonably achievable at the time of my review, or if the expected in-service date had been delayed beyond June 2015. Other projects were targeted for review for various reasons, including the size of the capital expenditure, timing, or project complexity. The EMS/SCADA replacement and the two projects for environmental upgrades at Hunter unit 1 fall into this category. The Merwin Fish collection and the Mill Fork Lease acquisition were chosen to ensure that there was at least one project in each of the hydro and mining categories. Projects such as the new substation at West Point are typically driven by load growth, and I wished to determine if the recent load projections still justified the need for this project. The remaining 17 sample projects were selected randomly.

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

A. After specifically targeting certain projects based on the various reasons discussed above, I also wanted to ensure that some projects were selected randomly to minimize the potential for “blind spots” in my review. By selecting some projects randomly, I ensured that any particular project had some chance of facing further review regardless of my or the DPU’s impressions from our initial review of the database.

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

A. First, I excluded all projects whose costs would be allocated entirely outside of Utah, and those already included in the sample. Of the 1,449 specific projects remaining in the database after these exclusions were made, more than half (744) were steam plant projects for less than one million dollars. I assigned a random real number between 0 and 1 to each of these small steam plant projects using Microsoft Excel's random number generator function. I selected the ten small steam plant projects with the lowest randomly-generated number. Finally, I used the same random selection technique to select seven additional specific projects from among the remaining 705 projects.

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 July 2013 to June 2015 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 (June 2015)?
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. Projects that will not be in-service by June 2015

Q: Please discuss the adjustments that you recommend that are related to projects that will not be in-service by 2015.

A: In response to data request DPU 35.1 seeking additional information about sample projects, the Company acknowledged that twenty projects are no longer projected to be placed in service before the end of the test year. Nine of these projects are in my sample, and are summarized in the table below. In response to data requests seeking additional information about sample projects, the Company also acknowledged that the Bigfork Penstock 3 Headgate Upgrade project will not be placed in service until 2017. The projected spending for these projects should also be removed from the Company's test year plant in-service. The adjustments related to these and the other removed projects are shown in Exhibit DPU 5.0, staff's direct testimony in this proceeding. The adjustments related to projects in my sample are summarized in Figure 14 below.

Figure 14

SAMPLE PROJECTS NO LONGER FORECAST IN TEST PERIOD

Project	EPIS FERC Account	July13 to Jun15 Plant Adds	Test Period 13 Month Avg. Plant Adds	UT Share - 13-mo Avg. Plant Adds
Craig CRGU1 U1 BFPT HOTWELL PUMPS UPGRADE	312	71,391	54,916	23,410
CRGU0 VEHICLE REPLACE CY14	397	26,953	14,513	6,187
HERMISTON U2 Buckets 1st Stage CY15	343	1,383,336	106,410	45,361
JB U3 APH Baskets 15	312	3,079,272	236,867	100,972
JB U3 Burners - Major 15	312	1,461,857	112,451	47,936
JB U3 Recoat Stack Lining 15	312	1,459,225	112,248	47,849
JB U3 Replace Cooling Tower 14/15	312	6,569,474	505,344	215,420
JB U3 Replace Finishing Superheater 15	312	11,693,325	899,487	383,436
Populus - Terminal 345 kV line - condemnation settlements	355	8,202,044	8,202,044	3,496,393
Bigfork Penstock 3 Headgate Upgrade	332	93,448	64,695	27,578
Total		**34,040,325**	**10,308,974**	**4,394,542**

Q: Are the projects discussed above the only sample projects that you believe will not be placed in service before the end of the test year?

A: No. In my review of sample projects I have determined that several others are highly unlikely to be placed in service in the test year, among other reasons for adjustment. These projects are discussed individually in the subsections below.

B. Casper Outer Loop – New 115 kV Red Butte to WAPA

Q: Please describe the Casper Outer Loop – New 115 kV Red Butte to WAPA project.

A: The Casper Outer Loop – New 115 kV Red Butte to WAPA project is the final phase of an ongoing project to convert the Casper Outer Loop from 69 kV to 115 kV operations. The cost of this project included in the Company's forecast of capital spending is $6.5 million and the listed in-service date is June 2015. The upgrade is required to satisfy the agreement outlined in Docket No. 20000-384-ER-10 between Rocky Mountain Power Company and other parties. In addition, the new configuration will allow maintenance on radial facilities and fulfill a reliability need in the area.

Q. What documentation has the Company provided in support of the project?

A. Based upon documents received in response to DPU Data Requests 6.6, 27.2 and 41.8 the Company has provided the following electronic documents.

1. APR 240002315.pdf (2011)
2. APR 940002301.pdf (2012)
3. APR 940025535.pdf (2012)
4. APR 94002937.pdf (2013)
5. Casper_Outer_Loop_Complete_115kV_Loop-IAD_2_1_2013.doc (2013)

6. Casper_Outer_Loop_Complete_115kV_Loop-Maps-Drawings_2_1_2013 (2013)

7. 13-035-184 RMP's Response to DPU Data Request 27.2 – 03-25-2014-Attachment.pdf

The first four documents include similar information on approved new project costs of [redacted] The facility study or its status was not provided and the Company confirmed in its response to DPU Data Request 41.8 that the documents referenced above were the only ones available for this project.

The inconsistency between the approved cost included in the capital database and approved cost provided by the appropriation request prompted me to request additional information on the approved cost of the project. The Company responded with additional information regarding the difference between the cost included in the Company's forecast and the documentation provided. More specifically, in its response to DPU 27.2, the Company claimed that the authorized expenditure approved by the multiple APR included in the response to DPU 6.6 is for preliminary funding only. Once all preliminary work is complete and the detailed estimate for the project is finalized, the Company confirmed that it will authorize a new APR for the full project cost.

RMP's Response to DPU Data Request 27.2 includes two project schedules from two different timeframes. The first, dated April 18th, 2013 is primarily focused on the activities required for the feasibility study and the second, dated March 10th, 2014, provides a high level estimation of the key delivery activities needed to meet the June 2015 in service date. These schedules are characterized by the Company as "high level" with a potential of being adjusted in coordination with WAPA.

Q. Is the provided documentation adequate for the project to be included in the Company's forecast of capital spending?

A. No. The Company has not provided any approved documentation to confirm the requested $6.5 million capital spending for this project. The four appropriation requests included in the response to DPU 6.6 have information related to preliminary costs for a facility study to be conducted by WAPA, but provide no additional information related to approved cost for other activities.

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

A. Yes, I do. The schedule provided in the response to DPU 27.2 denoted potential risks for the project's forecasted in service date. More specifically, the ROW easements have an actual start of 11/15/2013, but the schedule indicates that this activity has not started yet, resulting in a possible 4 month delay. The Company's response to DPU 41.8 confirmed that no ROW has been acquired. In addition, the Company identified potential scheduling risks due to the feasibility study results. As noted, the schedules provided are high level and there exists a possibility of changing the in-service date after coordination with WAPA regarding the construction schedule, which is in progress according to the Company's response to DPU data requests.

Q: What do you recommend?

A. The APR for this project states that the approved budget for this project is [redacted], not the $6.5 million reflected in the filing. The projected capital spending for this project should be reduced to $267 thousand.

C. Sigurd – Red Butte 345 kV line

Q: Please describe the Sigurd – Red Butte 345 kV line project

A: The project consists of a new 345kV transmission line between the existing Sigurd substation and the Red Butte substation in Utah. Besides the new transmission line, the project includes significant substation and control system additions, and modifications at both Sigurd and Red Butte substations. The cost of this project that is included in the Company's forecast of capital spending is $363 million and the listed in-service date is June 2015.

Q. Please discuss the issues concerning the project schedule for the Sigurd Red Butte transmission line project.

A: In the capital database provided by the Company, this project showed an expected in-service date of June 2015. DPU Data Request 27.3 requested a copy of the project schedule. The original schedule provided did not contain sufficient detail in order to assess whether the proposed in-service date was achievable. During a conference call with Company representatives on April 14, 2014, I asked questions about project scheduling in general and requested a more detailed project schedule for this proposed transmission line. On April 17, 2014, I received two separate project schedules - one for the transmission line and one for the substations. [redacted]

[redacted] I conclude it is unlikely that this project can be placed in service by June 30, 2015 as the schedule provided by the Company calls for. As a result, this project should be removed from the forecasted test year, as it will likely not be completed within that window.

Confidential Figure 15

[redacted]

D. West Point- New 138 kV line & 40 MVA Substation

Q: Please describe the West Point – New 138 kV line & 40 MVA Substation.

A: The West Point – New 138 kV – New 138 kV line & 40 MVA Substation includes the construction of a new 40 MVA substation with four distribution feeders at West Point and the development of 4 miles of a new 138kV line that will connect the Clearfield South substation with the new West Point substation. The cost of this project included in the Company's forecast of capital spending is $15.4 million and the listed in-service dates of April and May of 2015. The $15.4 million are distributed into $8.8 million for the transmission component of the project and $6.6 million for the distribution component.

Q. What documentation has the Company provided in support of the project?

A. Based upon documents received in response to DPU Data Request 6.6, the Company has provided the following electronic documents.

1. APR 94000991.pdf (2011)
2. APR 94001886.pdf (2012)
3. APR 94002534.pdf (2012)
4. Transmission Route.pdf
5. West Point New 138kv Ln 40mVA Rev2 ER.pdf (2009)
6. West Point IAD_02-03-2012.doc (2012)
7. WestPointRevIADApprdxCmpltr4.pdf (2010)

The Company provided information that confirmed the need for this project. More specifically, the load analysis included in the IAD was confirmed with additional information provided by the Company in response to Data Request DPU 41.10.

Q. Is the provided documentation adequate for the project to be included in the Company's forecast of capital spending?

A: No. The Company did not provide adequate approved documentation pertinent to the $15.4 million total cost of the project. APR# 940002534 includes approved capital expenditure of $[redacted] or $[redacted] less than the amount included in the capital database. The Company, in its response to DPU. 41.10, explained that the $15.4 million included in the capital database is an updated cost estimate developed in 2013, and that the Company is in progress of creating a new APR with the updated funding level.

Q. Do you have other concerns related to the West Point project?

A: Yes, I do. The Company did not provide any documentation related to the construction schedule of the project, making it difficult for me to assess the attainability of the proposed in service date. More specifically, the Company claimed in its response to data request DPU 41.1 that there is no construction schedule available at this point, but the construction of this project is slated to start in October 2014 with an in service date of May 2015. Unfortunately, there was no way for me to confirm this schedule.

Q: What do you recommend?

A. The Company did not provide any documentation to confirm the West Point project will be in service within the test year. Therefore, I recommend removing this project from the capital database. If the Company can provide a schedule reasonably showing the project completion to fall within the test year, I recommend allowing the project's inclusion at the $13.9 million figure in the currently approved APR unless an updated APR is also properly completed that shows a different and reasonable expenditure.

E. Whetstone 230-115 kV Substation Phase

Q: Please describe the Whetstone 230-115 kV Substation Phase

A: The Whetstone 230-115 kV Substation Phase includes the construction of a new 230-115 kV substation at Whetstone and a new 230 kV transmission line. The cost of this project that is included in the Company's forecast of capital spending is $17.7 million and the listed in-service date is June 2015.

Q: Please discuss the issues concerning the project schedule for the Whetstone substation project.

A: In the capital database, the forecast in-service date of this project is June 2015. In response to a data request for the project schedule the Company provided a schedule that did not contain sufficient detail in order to assess whether the proposed in-service date was achievable. During a conference call with Company representatives on April 14, 2014, I asked questions about project scheduling in general and requested a more detailed project schedule for this proposed transmission line. On April 17, 2014, I received an additional construction schedule for this project that contained some additional details as of April 3, 2014. Upon review of that additional schedule, I noted that [redacted]

[redacted] This schedule places the in-service date for this project outside the window of the test year. Thus, based upon the Company's own schedule, I conclude that this project is unlikely to be placed in service by June 30, 2015, and should be removed from the capital database.

F. EMS/SCADA Replacement Project

Q: Please describe the EMS/SCADA Replacement Project

A: The Supervisory Control and Data Acquisition Energy Management System (EMS/SCADA) is the core hardware and software system used to manage PacifiCorp's transmission and distribution system. PacifiCorp's existing system is 10 years old and relies on obsolete software and hardware that is no longer supported and must be replaced for NERC reliability and compliance purposes. [redacted][14] According to the capital projects database, the project has a total cost of approximately $27.8 million, with $19.9 million in software costs (categorized as Intangible) and the remainder in hardware and facilities costs (categorized as General).[15] The project is scheduled to be completed by [redacted].[16]

[14] PacifiCorp Appropriation Request Summary Report. Attachment to RMP's Response to DPU 6.6.
[15] RMP's response to DPU Data Request 27.1(a).
[16] Project Schedule. Attachment to RMP's Response to DPU 27.1.

Q. What documentation has been provided by the Company in support of this project?

A. The Company has provided the following documentation related to the EMS/SCADA Replacement Project:

- PacifiCorp Appropriation Request Summary Report[17]
- EMS/SCADA Replacement Project Proposal[18]
- Project schedules[19]

Q. Has the project received proper approvals?

A. Yes it has. Since the total cost of this project is greater than $25 million, it requires the approval of the PacifiCorp CEO.[20] The APR document lists [redacted] as the project approver,[21] but the Company has provided additional documentation that the project has been approved by PacifiCorp CEO Greg Abel[22] and his approval is acceptable under corporate governance policies.

Q. Did the Company consider alternatives to this project?

A. Yes. According to the project proposal and the APR documentation, [redacted]

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17 PacifiCorp Appropriation Request Summary Report. Attachment to RMP's Response to DPU 6.6.
18 EMS/SCADA Replacement Project Proposal. Attachment to RMP's Response to DPU 6.6.
19 Confidential Attachments to RMP's Response to DPU 27.1, Confidential Attachment to RMP's Response to DPU 22.5 (5th Supplemental).
20 PacifiCorp Corporate Governance and Approvals Process. December 31, 2012, p. 13.
21 PacifiCorp Appropriation Request Summary Report. Attachment to RMP's Response to DPU 6.6.
22 Attachment to RMP's Response to DPU 41.32.

[redacted]

Q. Do you have any concerns with the project?

A. My primary concern with this project is the schedule. Based on the information provided by the Company, I have little confidence that the project will be placed in service on schedule, or prior to the June 30th, 2015 deadline to be included in the test year plant in service total.

The Company has provided [redacted] versions of the detailed project schedule to date.[23] [redacted]

I have reviewed the various versions of the project schedule. The oldest schedule provided was created on [redacted], and the most recent update is dated [redacted] A review of the intervening schedules demonstrates [redacted] However, the evidence suggests that the final in-service date will be delayed due to the significant delays in key tasks.

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[23] Confidential Attachment to RMP's Response to DPU 27.1; Attachment to RMP's Response to DPU 27.5.

Q. What leads you to conclude the project will be delayed beyond June 30, 2015?

A. [redacted]

[redacted]

[redacted] If this trend continues, the project will not be in service until well beyond the June 30, 2015 deadline.

Q. Has the Company implemented any business arrangements that would provide some protection to customers in the event of a delay in this project?

A. It is my understanding that much of the work on this project is being performed by a contractor, and that the Company has negotiated a "guaranteed" in-service date in its contract with this contractor. Specifically, I understand that if the project is not completed as scheduled, the contractor will pay liquidated damages to the Company. Any liquidated damage payments received by the Company should serve to reduce the capital costs that are included in plant-in-service, and ultimately in rates. I do not know the value of these liquidated payments. However, if the project is delayed beyond June 30, 2015, as I believe it will be, any liquidated damage payments will not be received until after June 30, 2015. While the receipt of liquidated damage payments should reduce the capital cost of this project compared to what it would cost without liquidated damages, such a reduction will not occur in this rate case but should occur in the next rate case or in future rate cases. Therefore, the existence of the liquidated damages provision does not affect my opinion that this project should be removed from the forecasted plant-in-service levels to be used in setting rates in this proceeding.

Q. What are your recommendations regarding the EMS/SCADA project?

A. Based on the information provided by the Company, I am convinced that the actual in-service date of this project will be delayed beyond June 30, 2015. Therefore, the capital expenditures associated with the project should be removed from the test year plant in service.

G. FC 200 to FC300 Replacement (Obsolescence)

Q: Please describe the FC200 to FC300 Replacement (Obsolescence) project.

A: The FC200 to FC300 Replacement project consists of an upgrade to the existing Itron FC200 meter reading handheld devices installed in 2008 and used in the Company's Itron Field Collection System. The current FC200 devices are no longer offered by the vendor and vendor service support for PacifiCorp is scheduled to expire in March 2014. The cost of this project that is included in the Company's forecasted capital spending is $1,127,016. The project was placed in-service in August 2013 with an actual addition to plant in-service of $1,328,135.

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

A: In response to data requests seeking all supporting documentation related to this project, the Company has provided four documents.

1) Investment Appraisal 2012 (Attachment DPU 22.6-1)
2) Economic Project Evaluation (Attachment DPU 22.6-2)
3) Appropriate Request Summary Report (Attachment DPU 22.6-3)

4) Actual Cost Breakdown by State (Attachment DPU 41.37)

Q: Has the project received required approvals?

A: According to the Appropriation Request Summary Report, the project was approved on 11/15/2012.

Q: Are the benefits to Utah commensurate with Utah costs?

A: In response to DPU Data Request 41.37, the Company specifies the actual costs of the project by state. The Company explicitly states and verifies in an attachment that includes cost breakdown by state that 20% of total project costs are for Utah facilities. In the capital expenditure database, Utah is assigned a percentage of this project's total costs using the System Generation ("SG") allocator. Utah's share of costs allocated using this factor is 42.63%. Under this allocation, Utah ratepayers are responsible for a substantially higher portion of the total project cost than PacifiCorp's analysis.

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

A: Expenditures for handheld meter reading devices are appropriate for direct allocation to the jurisdiction in which they are used. Given the detailed cost breakdown and the localized impact of the new meter readers, the allocation of cost for this project should be changed from SG to in situs by state. The project cost directly allocated to Utah should be $279,160.

H. Hydro Vehicles 2015

Q: Please describe the Hydro Vehicles 2015 project.

A: This project appears to consist of the replacement of vehicles related to PacifiCorp's hydro generators. The project cost in the capital database is $674,269 and has an in-service date of June 2015. This particular project is the 2015 budget for a recurring capital project related to the purchase of new vehicles in order to provide safe and reliable transportation for employees and reduced maintenance costs. There is also a "Hydro Vehicles 2014" project in the database, and the Company has provided historical spending on this project since 2008.[24]

Q: How did the Company determine the cost of this project?

A: Despite data requests for project documentation in DPU 22.6, 41.17, and 41.18, the Company has not provided any materials supporting the specific cost estimate. The only explanation provided is that "The budget number is associated with past history and approved budgets."[25] Based on the Company's responses to other discovery requests, I believe that PacifiCorp has a forecasted budget amount for vehicle replacements as part of their long term budget. Then, each December, they determine which vehicles will need replacement in the following year.[26] Orders for these vehicles are placed in January and APR documentation is prepared at that time.[27] Therefore, the Company currently has no documentation for the 2015 expenses, and apparently no workpapers for determining the specific amount included in the database. Instead, the Company states that cost

[24] Attachment to RMP's Response to DPU 41.16.
[25] RMP's Response to DPU 41.18.
[26] RMP's Response to DPU 41.17.
[27] Ibid., RMP's Response to DPU 41.19.

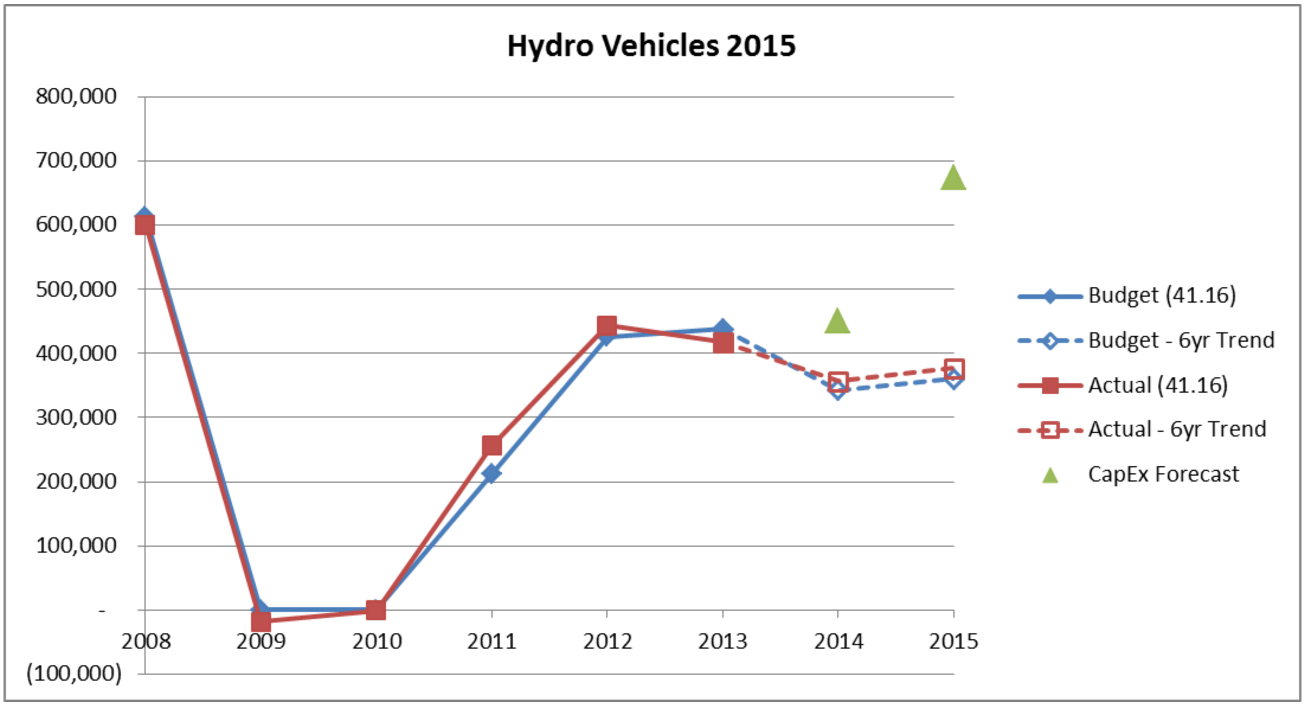
projections are "based on prior experience…", and that: "timing specifics are addressed and documentation is prepared when equipment failures occur."[28]

Q: What is your recommendation for this project?

A: Based on the fact that this project is one year's budget of an ongoing capital project, and that the Company does not have documentation on specific vehicles to be replaced, I think it is reasonable to treat this project in a similar manner as the generic project discussed above. Therefore, I have used the historical data provided to perform a trend analysis similar to the analysis on the generic projects discussed above.

[28] RMP's Response to DPU 22.6.

Figure 16



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

A: Based on the results of the trend analysis above, the forecasted expenses for hydro vehicles in 2015 appear very high. Without any documentation of specific vehicle replacements or explanation for how the budgeted amount was developed, I recommend the amount be reduced to the level indicated by the trend analysis, $377,239.

I. Vehicle Replacement

Q: Please describe the Vehicle Replacement project.

A: Despite discovery requests in DPU 22.6, 41.21 and 41.22 for project documentation, the Company has not provided any materials explaining the purpose of the project and its cost estimate of $40,000. The Company's claims that an APR is still pending, "the project was approved in the development of the budget," and that the "cost estimate was based on an escalated historical cost of the item." No technical or historical data or approval documents have been provided nor a project schedule for an in-service date of July 2014.

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

A: Without any evidence of project approval or planning, this capital project should be removed from the projected spending total.

J. Mill Fork South Lease Acquisition

Q: Please describe the Mill Fork South Lease Acquisition project.

A: The Mill Fork South Lease Acquisition is a project to [redacted]

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

A. The plant in-service for this project should be removed from the test period. In the confidential response to DPU Data Request 42.5, the Company states, "[redacted]" Given that this response was dated April 21, 2014, it appears that the project is behind schedule in comparison to the Project Milestones given in the APR dated [redacted]. The APR shows [redacted]. Because the project is behind schedule and the Company has not provided an updated schedule, I believe it is unlikely that this milestone will occur within the test period.

XI. Issues from the Prior General Rate Case

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. In Docket No. 11-035-200, the documentation provided by the Company indicated a May 2012 in-service date. According to the response to DPU 20.10, this project has been placed in service. In Docket No. 11-035-200, I raised concerns about the Company's forecast of capital expenditures for this project. Specifically, I questioned whether the Company had sought the proper amount from the developer of this project as a contribution in aid of construction (CIAC). Since the prior rate case was resolved by a settlement, the Commission did not decide this issue. Given that the issues I raised were not addressed, I performed another review of this project in this proceeding.

Q: Please describe the issues raised in your previous testimony on City Creek in Docket No. 11-035-200.

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 in Docket No. 11-035-200, the Company does not waive the extension allowance.

In response to DPU Data Request 31.2 in Docket No. 11-035-200, 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 was budgeted in the project documentation, indicating that the Company expected the developer to make a CIAC payment. Even when the developer constructed certain distribution facilities at its expense of $5.55 million, it still made a 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 17 below. Based upon my analysis, I found that the CIAC payment from the developer of City Creek should have been $21 million, not the $7 million figure sought by the Company. Therefore, I recommended that the forecast of capital additions to be included in the Company's base rates be reduced by $14 million.

Figure 17

(Figure 15 from Hahn Direct Testimony in Docket No. 11-035-200)

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		

Q: Did the Company respond to your recommendation described above in Docket No. 11-035-200?

A: Yes. In the rebuttal testimony of Douglas Bennion, the Company disagreed with my analysis and recommendation. In that testimony, the Company stated that there was no requirement to collect CIAC from the developer of this project. Instead the Company assigned $7 million of the project's cost estimate for "non-allowable trenching and vault costs". Figure 18 below provides an excerpt from Mr. Bennion's rebuttal testimony in Docket No. 11-035-200 that shows how he analyzed the City Creek project.

Figure 18

(Figure 1 from Bennion Rebuttal Testimony in Docket No. 11-035-200)

	PRI Non-Allowable [1]	PRI Allowable [2]	RMP [3]	Total
Phase 1 & 2	$3.00	$2.81	$3.69	$9.50
Phase 3	$4.00	$1.15	$29.05	$34.20
Total	$7.00	$3.96	$32.74	$43.70

PRI Commercial Revenue	$7.82		
Commercial Allowance	$10.43		
#Residential units	550		
Residential Allowance	$0.61		
	Residential	**Commercial**	**Total**
PRI Allowable Project Costs[4]	$0.49	$3.47	$3.96
PRI Extension Allowance (min of allowance vs cost)	$0.49	$3.47	$3.96
CIAC Requirement	**$0.00**	**$0.00**	**$0.00**

1 PRI Non-Allowable costs include the work and equipment associated with the installation of vaults and conduits performed by PRI. RMP is given ownership of these assests upon completion.
2 PRI Allowable costs include the work and equipment associated with installation of the facilities directly assignable to PRI excluding the trenching and vault costs contributed by PRI via the Non-Allowable costs.
3 RMP costs include the work and equipment for the infrastructure considered as overall system improvements/upgrades.
4 PRI allowable project costs were allocated between residential and commercial based on their respective loading portion of the total load.

Q: Has the Company's rebuttal testimony in Docket No. 11-035-200 or any other information provided in this proceeding caused you to change your opinion

regarding how to determine the amount of contribution that the developer of City Creek should have paid?

A: No. I disagree with the analysis contained in the rebuttal testimony from Docket No. 11-035-200. It does not appear to be consistent with electric service regulation number 12 regarding line extensions for new customers. In response to DPU 20.10 in this proceeding, the Company provided a Post Investment Review ("PIR") of the City Creek project. In that document, it is clear that the $7 million reimbursement from the developer is a CIAC payment. The PIR also states that "much of the existing distribution facility locations conflicted with the new development and required demolition". Thus, in the absence of the proposed City Creek development it is unlikely that those distribution facilities would require relocation. I also point out that the PIR confirmed that the City Creek load is 32.2 MVA, which is even higher that the 27.5 MVA prior estimate for City Creek. Existing loads in this area were confirmed to be 14.3 MVA. Even though the City Creek project represent 66% to 69% of the total load in this area after City Creek is built, Mr. Bennion assigned only 25% of the costs of this project to the developer. This assignment of costs is inconsistent with the increase in load that is clearly driving the need for this project and the bulk of its costs.

Q: Based upon information provided in this proceeding would you revise the estimate of CIAC that the developer of City Creek should have paid?

A: I believe that the method that I used in Docket No. 11-035-200 is still reasonable. However, it appears that project actual cost came in close to budget without the contingency allowance. Therefore, I revise my estimate by removing the amount of contingency from the project costs and performing the same calculations as I did in the previous proceeding. This results in a revised estimate of the proper CIAC of $17.85 million. This is the amount that the Company should have collected. Since it only collected $7 million, I believe that it under-collected by $10.85 million. I recommend that the plant in service forecast in this proceeding be reduced by $10.85 million. Figure 19 below shows the calculation of this revised amount.

Figure 19

REVISED 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	
less contingency	$4.37	$3.21	$1.16	
	$39.33	$28.89	$10.44	
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		$17.85		
PRI Actual CIAC		$7.00		
difference		$10.85		

XII. Late-Filed Additions to Capital Projects Database

Q: Has the Company proposed to include in its forecast of capital additions and plant in service any new projects that were not included in the filing requirements?

A: Yes. Four questions in DPU data request set 35 asked for projects that fell into the following categories.

1) Projects in the capital database that have been delayed or canceled past June 2015 (DPU 35.1);
2) Projects in the capital database that were originally forecasted to be placed into service in the July 2013 to February 2014 period but were delayed until the March 2014 to June 2015 time period (DPU 35.2);
3) Projects in the capital database that were originally forecasted to be placed into service in the March 2014 to June 2015 time period that now have an earlier in-service date than the original filing (DPU35.3); and
4) Projects that were not in the original July 2013 to June 2015 forecast that are now expected to be placed into service during the March 2014 to June 2015 time period. (DPU 35.4)

In response to the fourth question in DPU 35.4, the Company provided a list of 10 projects that it now proposes to include in its forecast of additions to plant in service between March 2014 and June 2015 that were not included in the original filing requirements. Exhibit DPU 3.5 Dir-Rev Req provide a description of those projects, the-service dates, and the amount expected to be spent. The total amount of capital expenditures during the forecast period is approximately $25.9 million.

Q: What is your reaction to this proposed list of new additions?

A: It is my understanding from discussions with DPU staff that, in recent general rate cases, it has been common practice to update forecasts of plant in service for actual capital spending that may have occurred since the preparation of the filing. Since the status of projects in the filing requirements is being updated, it is not unreasonable to also consider deleting some projects whose schedules have changed and adding new projects. I note that subsequent to our data requests on the timing and project schedules or several key originally proposed capital additions and in response to DPU 35.1, the Company has revised its schedule for approximately 20 projects which previously were projected to be in service prior to June 2015, but are now projected to be completed after June 2015. These schedule changes reduce the projected plant in service by $57.8 million. Since the newly proposed projects were not in the original filing requirements, I have not yet analyzed them nor have I conducted detailed discovery on these projects. However, newly proposed projects should be subject to some level of assessment prior to being included in an approved forecast of plant service. The same types of information that I requested on projects listed in the original filing requirements should be provided for these newly proposed projects. This information should include authorization documents required by the Company's own policies (including but not limited to IADs, ERs, PCNs), technical assessments and studies that justify the need for these projects, and project schedules showing that they can be completed as forecast.

Q: Was the Company asked to provide supporting documentation for any newly proposed projects?

A: Yes. DPU Data Request 35.4 specifically asked the Company to provide "all supporting documentation for these projects. Supporting documentation should include, but not necessarily be limited to expenditure requisitions, appropriation requests, investment appraisal documents, engineering service agreement studies, project change notices, or any other relevant studies, analyses, reports and spreadsheets (with formulae intact)".

Q: Has the Company provided the documentation that was requested for these 10 newly proposed projects?

A: Based upon discovery responses received to date, the Company has not provided sufficient documentation. In fact, the only document that I received is a one-page high level project schedule for the Pomona Heights substation work. Exhibit DPU 3.5 Dir-Rev Req contains a copy of that single page of documentation. No documentation was provided for any other of these 10 projects. Given the inadequacy of the supporting documentation provided to date, I would recommend that none of the 10 newly-proposed projects be included in the forecast of plant in service until such documentation has been provided, reviewed, and found to be adequate.

XIII. 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. Any additional documentation must be provided immediately so that it can be meaningfully considered within the confines of this rate case schedule.

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.