PUBLIC MEETING

Utah Committee of Consumer Services

May 29, 2013

Welcome & Business

Annual Training:
Open and Public Meetings Act

Case Updates

New and Anticipated Filings

- Questar Pass-Through Filing
  - Requested increase of $61 million for the forecasted May 2013 – May 2014
  - The increase represents an annual bill increase of $47.39 or 7.08% for the typical residential customer using 80 Dth
  - Primary driver: increasing fuel costs
- Questar General Rate Case
  - Anticipated to be filed July 1, 2013
  - Office issued RFPs for experts in Revenue Requirement and Cost of Capital

Case Updates

- Legislature
  - May meeting of the Public Utilities and Technology Interim Committee included an overview of the utility regulatory process
- RMP Irrigator Programs
  - Load Control Tariff: approved
  - Net Metering Alternate Annualized Billing Period: approved
- Wexpro II
  - Technical Conference to discuss filing requirements for requests to add properties under the agreement
- SB 275 (alternative fuel vehicles)
  - PSC established a schedule: comments July 3, reply comments August 1
  - Hearing: August 7, Public Witness Day: August 8

Case Updates

- Manti
  - Settlement in principle regarding issue on reconsideration
  - Manti has hired new consultants and has management turnover
  - New case expected to be filed later this summer
- Voluntary Request for Approval (SCR systems: Jim Bridger 3 & 4)
  - PSC approved on May 10
    - Approval referenced a specific cost (lower than total request); if executed contract is lower than approved amount is lowered
    - If EPA issues a final rule imposing a 0.05/MMBtu NOx emissions limit, the approved cost is increased to original request
    - In light of uncertainties, the approval is conditioned on the Company acting prudently when responding to potential new information and changed conditions
  - RMP requested clarification on May 17
    - The calculation of the specific approved cost
    - Recovery of total project cost, not just the EPC contract cost

Other Ongoing Cases

- RMP Renewable QF Pricing (hearings next week)
- RMP Energy Balancing Account
- RMP REC Balancing Account
- Questar IRP
- RMP DSM tariff changes
- RMP Depreciation (presentation today)
- PacifiCorp IRP (presentation today)

PacifiCorp Depreciation Filing

Utility Depreciation 101

- Depreciation: all tangible utility plant (except for land) are depreciable, meaning they are subject to wear and tear, decay, and obsolescence as they provide service over time.
- Depreciation Method: a straight line depreciation (SLD) method is commonly used for depreciating utility plant.

  SLD Formula: (Original Cost - Net Salvage)/Service Life
- Estimates must be made for net salvage & service lives.
  - New Gas CCCT Plant Example:

    ($650,000,000 - $50,000,000)/ 40 = $15,000,000 in annual depreciation expense.

Utility Depreciation 101

- Depreciation Rates: The chief objective of a depreciation study is to determine appropriate life spans, salvage values, removal costs, etc. in establishing depreciation rates for a utility's plant.
  - Specific rates are determined by plant account: production, transmission, distribution, general, etc.
  - A composite depreciation rate is calculated, which reflects a "roll-up" of the individual rates by plant account.

- Depreciation Rate Formula:

$$\frac{(\text{Original Cost} - \text{Net Salvage})/\text{Service Life}}{\text{Original Cost}} = \text{Deprec. Rate (\%)}$$

Utility Depreciation 101

Why Depreciation Matters in Ratemaking

- Traditional Rate Formula

  R = O + (A-D)r

  R = utility's revenue requirement

  O = operating expenses, depreciation and taxes

  A = gross value of capital investment

  D = accumulated deprecation = plant that has been depreciated or recovered through rates

  (A-D) = rate base or net capital investment

  r = rate of return on rate base

Utility Depreciation 101

Depreciation Rates:

- Impacts Utility Earnings
  - Several important factors impact a utility's earnings:

    1) the level of capital investment;

    2) the speed at which that investment is depreciated over time;

    3) the allowed return (r) on that investment.
- Impacts Rates Paid by Customers
  - Setting life spans for utility plant correctly matches the payees and beneficiaries for those resources.
  - A significant mismatch between cost recovery through depreciation rates and actual service lives of plant can result in inter-generational inequities among customers.

PacifiCorp 2013 Depreciation Case

- PacifiCorp files a depreciation case about every five years
- Filed January 22, 2013 in all PacifiCorp states.
  - PacifiCorp strives to maintain consistent depreciation rates for generation and transmission plant across the states.
  - Different levels and vintage of distribution plant investment results in different depreciation rates for distribution assets in each state.
- PacifiCorp used the expert Gannett-Fleming to prepare the Depreciation Study supporting its proposed changes to depreciation rates and expense.
  - Gannett-Fleming has prepared many depreciation studies for electric and gas utilities over the years.
  - Direct Testimony filed by John Spanos of Gannett-Fleming and two additional Company witnesses.

Implementation of the Depreciation Case

- Changes to depreciation rates & expense impact customers' electric bills after the next general rate case (October 2014 time frame).
- 2014 rate impact capped at $2.0 M annually
  - Increases above that level are deferred without interest over 17 years.
  - Cap is only applicable to the base (non-Carbon Plant) amount requested.
- The treatment of the Carbon Plant is subject to specific cost recovery provisions included in the last rate case settlement.

Key Drivers

- New pollution control equipment (PCTs)
  - Added to certain coal units to meet new environmental requirements.
  - Depreciated over the remaining coal unit lives.
  - Example: Bridger SCR investment of $XXX million targeted for 2015. This investment will be amortized into rates over 22 years instead of 61 years had the SCRs been included with the original plant investment.
  - Interim retirements
  - Replaced aging equipment on generation plant with new components has the effect of increasing depreciation expense.
  - Mining
  - Reduced both the estimated recoverable coal reserves and life span of the Deer Creek Mine.
- Carbon Plant retirement

Depreciation for Carbon Plant

- Carbon Plant: scheduled retirement date advanced from 2020 to 2015.
- Stipulation in the last GRC provided for deferred accounting treatment for the Carbon Plant:
  - A first regulatory asset was created for the remaining, un-depreciated plant balance.
  - A second regulatory asset was created for the estimated costs of removing the Carbon Plant from service.
  - The Company still carries the burden to demonstrate prudence of the costs included for each regulatory asset.
- Impact of Carbon Plant: Increases depreciation expense by $32.4 million on a Utah basis.

Cost Breakdown by Category

- Summary of Impacts w/o Carbon Plant Retirement:
  - Requested changes to depreciation rates in the study results in a new composite depreciation rate of 2.91%.
  - Applying the 2.91% rate to projected Dec. 2013 depreciable plant balances results in a increase on a Utah basis of $38.1 million.
- Breakdown of Increase (w/o Carbon): $38.1 M
  - Production Plant - $37.0 M
  - Transmission Plant - ($2.0) M
  - Distribution Plant - ($1.5) M
  - General Plant - ($0.5) M
  - Mining - $5.1 M
- Total Proposed Utah Increase (w/Carbon): $70.5 M

OCS Analysis

- The Office retained Jack Pous, of Diversified Utility Consultants, to assist with the technical aspects of the analysis
  - Mr. Pous is a longstanding expert in the utility depreciation area and has filed testimony in over 100 utility depreciation cases.
  - Mr. Pous worked for the Office on the previous two PacifiCorp Depreciation Filings (2001 and 2007)
- Litigation strategy will be discussed during Closed Session.

Case Schedule

- The schedule for the depreciation case is as follows:
  - Direct Testimony Due: June 21, 2013
  - Rebuttal Testimony Due: August 2, 2013
  - Surrebuttal Testimony Due: August 27, 2013
  - Settlement Conference: TBD
  - Commission Hearings: September 11-12, 2013
- A multi-state meeting is scheduled (May 30) to discuss initial concerns with the Company's depreciation study and proposed depreciation rates

PacifiCorp 2013 Integrated Resource Plan

Purpose of the IRP

- Develop a long range resource plan to meet forecasted load requirements (20 - year planning horizon).
- Determine an optimal set of resources to ensure adequate and reliable supply of electricity while balancing:
  - Cost
  - Risk
  - Public Policy Goals

IRP Process

- PacifiCorp is required to submit an IRP every two years for review and possible acknowledgment by the Commission.
- IRP Acknowledgment = Complying with Commission's IRP Guidelines
- Key IRP guidelines include:
  a. An evaluation of resources on a consistent and comparable basis;
  b. A 20-year planning horizon;
  c. An 2-4 year action plan to implement the IRP results, consistent with the business plan;
  d. A range of peak and energy load growth forecasts (system and by state).
- Interested parties have the opportunity to submit formal IRP comments and recommendations to the Commission.
- Information from the IRP is used in many other state and regional processes

Resource Needs

Key Information:

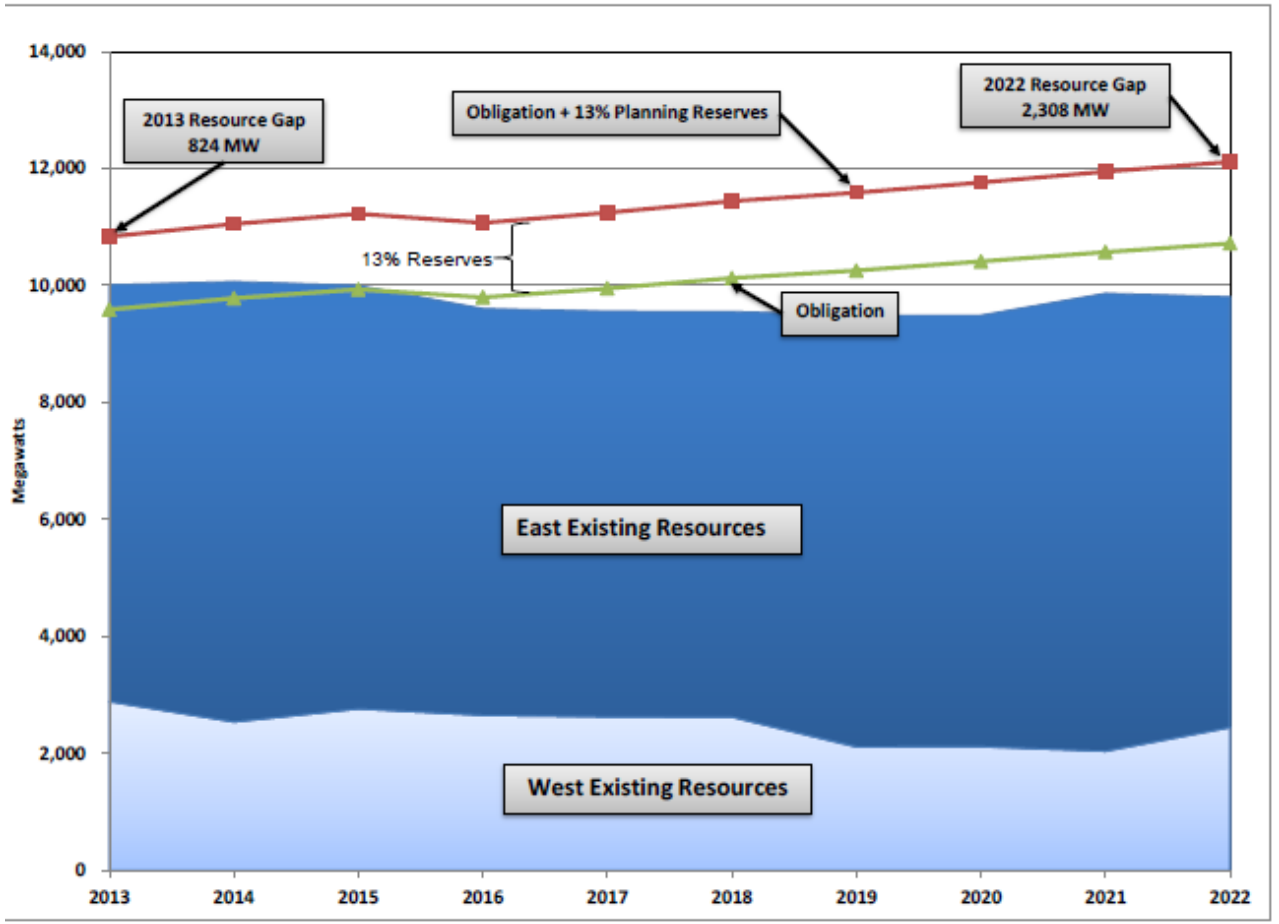
- Forecasted Loads = Obligation
- Planning Reserve Margin (PRM) = 13%
- Current Resources - (Obligation + PRM) = Annual Surplus/Deficit

System Position (Capacity):

- Capacity: 2013 (824 MWs) Resource Deficit
  2022 (2,038 MWs) Resource Deficit
- Energy: 2018 (1 month w/energy shortfall - July)
  2022 (4 months w/energy shortfall)
- Bottom Line: Capacity deficits are driving the need to acquire resources over the next 10 years and certain resources are better suited to meet capacity requirements.

PacifiCorp's Load – Resource Balance

Figure ES.3 – PacifiCorp Capacity Resource Gap



Case Development

- Reference (3 Cases): Different RPS requirements (none, state only, state and federal)
- Environmental Policy (11 Cases). Different combinations of regional haze reqs., market prices, CO2 prices, RPS reqs. and DSM levels.
- Targeted Resources (4 Cases): Special cases involving market price spike, forcing geothermal PPAs to meet RPS requirements, accelerated DSM acquisition, maximum clean energy resources.
- Transmission Alternative (1 Case): Transmission capacity purchased on Zephyr Line from 3rd Party provider, as alternative to Pacificorp's Windstar to Populus line.

Case Development: Inputs & Assumptions

- Load Growth: lower capacity forecasts
  - Avg. annual system growth rate for capacity for 2012-2022 is 1.2% for the 2013 IRP; was 2.1% in 2011 IRP.
  - Utah at 1.88% stronger than other states (especially Northwest states).
- Resource Costs: lower cost estimates for wind; similar to past estimates for other resources
- Asset Lives: longer life span for wind; assumes Carbon plant retired in 2015
- Natural Gas Costs: lower natural gas price forecasts
- Market Prices: lower price forecasts at western market hubs
- Carbon Tax: assumed effective 2022 at base level of $16/ton with escalation
- Wind Integration Costs: lower cost estimate of $2.55/MWh.
- Renewable Tax Credits: eliminated in all core cases except Case 18.
- Renewable Portfolio Standards: RPS additions determined in external model.
- Demand Side Management (DSM): increased granularity
  - DSM resources now grouped into 27 different cost levels vs. 9 in 2011 IRP

Studies Contributing to Case Development

- Updated Wind Integration Study - Results show much lower wind integration costs ($2.55/MWh) in the 2013 study. Lower natural gas costs and market prices contribute to this lower estimate. Technical Review Committee was formed to provide comments on the study.

- Coal Conversion Analysis - Economic comparison of converting coal units to natural gas vs. investments in pollution control technologies (PCT) to comply with emissions requirements. The analysis shows it is cheaper to invest in PCTs and continue to run the coal units over their expected lives.

- DSM Potential Study (Cadmus) - Results show a decrease in the 20-year, DSM technical potential that is achievable. The prior study indicated 1,528 aMW and the new study shows 971 aMW.

Least-Cost Analysis

- System Optimizer Model
- Developed 95 cases for the 2013 IRP
  - Core Cases (19) x Energy Gateway Transmission Platforms (5)
  - Sensitivity Cases (7); load forecasts - low, high & extreme weather
- System Optimizer model solves for least cost mix of resources for each case based on PVRR (Present Value of Revenue Requirement).
  - PVRR = the value today of future resource investments for each case, discounted at an interest rate (6.882%).

Risk Analysis

- Planning and Risk Model (PaR) – Monte Carlo Simulation
- Risk Analysis tests the ability of the 19 core cases to respond to random, sometimes major changes, in the following variables:
  - Loads
  - Natural Gas Prices
  - Wholesale Electricity Prices
  - Hydro Energy Availability
  - Outages for New Thermal Plants
- PaR Model screens cases based on the combination of average risk and upper-tail risk
  - Upper-tail risk reflects potential outcomes that have a low probability of occurring but can be expensive if they do materialize
- 1st screen reduced to 36 cases; 2nd screen reduced to 12 cases

Selection of Preferred Portfolio

- Case EG2-C07 was selected as the preferred portfolio based on the following criteria:

	Rank
o Risk-adjusted PVRR	3
o CO2 emissions	7
o Supply reliability (ENS)	8
o Resource diversity	All Cases: Heavy Mkt P. & DSM (2012 -2022)

2013 IRP - Preferred Portfolio Overview

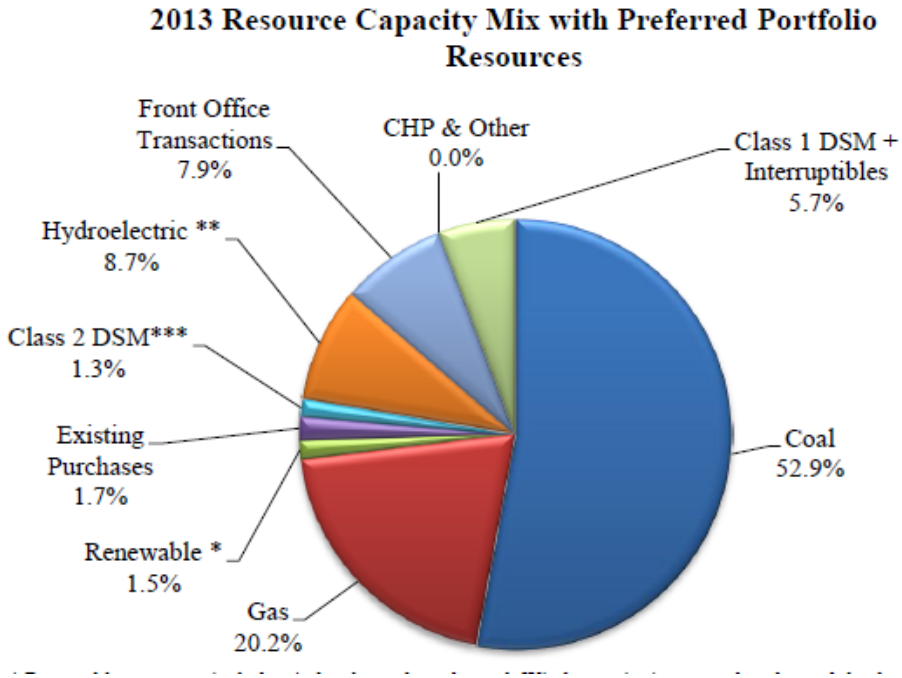
- Resources are limited to firm market purchases and DSM over the first 10 years of the planning horizon.
- No additional coal plants retired or converted to natural gas.
- First new gas plant, a 423 MW CCCT, added in 2024.
- Wind resources (Wyo.) are added in the 2024-25 period.
  - Access dependent on Energy Gateway segment EG-2, Windstar-Populus.
  - 2013 IRP Wind total = 650 MW vs. 2011 IRP total = 2,100 MW
- RPS requirements in OR, WA and CA met through RECs rather than the acquisition of resources.
  - Eliminates 200 MW of wind resources in 2018-2023 period.
- Modification to Preferred Portfolio: Acceleration of certain future DSM programs per “risk mitigation” benefits indicated in Case 15.

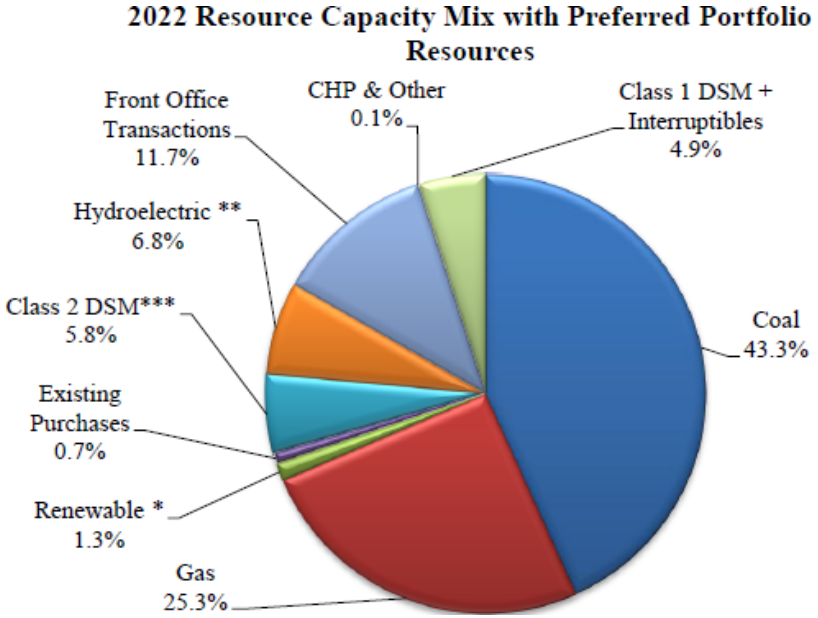
Preferred Portfolio Matrix

Table ES.3 – 2013 IRP Preferred Portfolio

Summary Portfolio Capacity by Resource Type and Year, Installed MW																					
	Installed Capacity, MW																				
Resource	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	Total
Expansion Options																					
Gas - CCCT	-	645	-	-	-	-	-	-	-	-	-	423	-	-	-	661	-	1,084	-	-	2,813
Gas- Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	181	-	-	-	181	362
DSM - Energy Efficiency	115	117	103	101	97	92	90	81	80	82	68	70	67	67	69	66	63	54	57	56	1,593
DSM - Load Control	-	-	-	-	-	-	-	-	-	-	-	-	-	-	85	19	88	-	-	-	193
Renewable - Wind	-	-	-	-	-	-	-	-	-	-	-	432	218	-	-	-	-	-	-	-	650
Renewable - Utility Solar	4	3	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10
Renewable - Distributed Solar	7	11	14	16	18	14	14	14	15	15	15	15	15	15	15	15	15	15	15	15	293
Combined Heat & Power	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	21
Front Office Transactions	650	709	845	983	1,102	1,209	1,323	1,420	1,191	1,333	1,427	1,112	1,304	1,425	1,469	1,464	1,472	1,231	1,281	1,246	n/a
Existing Unit Changes																					
Coal Early Retirement/Conversions	-	-	(502)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(502)
Thermal Plant End-of-life Retirements	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(760)	-	(701)	(74)	-	(1,535)
Coal Plant Gas Conversion Additions	-	-	338	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	338
Turbine Upgrades	14	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	14
Total	**791**	**1,486**	**802**	**1,102**	**1,218**	**1,315**	**1,427**	**1,515**	**1,287**	**1,431**	**1,511**	**2,054**	**1,606**	**1,509**	**1,640**	**1,648**	**1,639**	**1,685**	**1,281**	**1,500**	

Preferred Portfolio Resource Mix: 2013 & 2022





Related Issue: New "Systems Benefit Tool"

- Systems Benefit Tool was developed by the Company to capture incremental transmission benefits to those identified using the System Optimizer model.
  - Recently introduced by PacifiCorp; regulators and stakeholders have yet to evaluate the merits of the tool
- In the case of the proposed Energy Gateway Windstar –Populus transmission line, which is the line underlying the EG2-C07 preferred portfolio, the incremental benefit calculated by PacifiCorp is $655 M.
  - Windstar-Populus example: Total Benefit of $1.165 B – Total Costs of $934 M = Net Benefit of $231 M. Thus, the $655 M incremental benefit amount determined by the SBT is critical to demonstrating the proposed line is cost-effective.
- PacifiCorp proposes workshops be held this summer to more closely examine SBT.

OCS Review Plan

- Compliance with PSC's IRP Guidelines & past IRP Orders
- Reasonableness of methods, inputs, assumptions and ultimately the preferred portfolio of resources selected by the Company
- Flexibility in the Action Plan to meet unexpected developments
- Key issues impacting customer rates and reliability:
  - Heavy reliance on market purchases (availability & price risk)
  - Significantly lower amounts of wind resources
  - Accelerated DSM acquisition levels (near-term rate impacts, Utah)
  - Cost/benefits of Energy Gateway transmission investment (need, timing)
  - PCT investment for coal units over the next 10 years

2013 IRP – Next Steps

- Scheduling conference is set for May 30, 2013.
- Comments from interested parties will likely be due in the late summer/early fall period.
- In the past, the PSC's acknowledgement process has occurred without formal hearings.

Closed Meeting

Pursuant to Utah Code Section 52-4-205 (1)(c): Discussion of strategy in pending litigation before the Utah Public Service Commission

Other Business

Adjourn