# Rocky Mountain Power
# Utah General Rate Case

## Docket No. 20-035-04

*Technical Conference*

Phase I: Cost of Capital/Revenue Requirement

July 10, 2020






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# Agenda

Rate Case Overview
Presenting: Steve McDougal

Capital Structure
Presenting: Nikki Kobliha

Major Capital Projects
Presenting: Rick Link, Tim Hemstreet, Bob Van Engelenhoven

Major Transmission
Presenting: Rick Vail

Naughton Unit 3
Presenting: Dana Ralston, Steve McDougal

SCRs
Presenting: James Owen

Net Power Costs
Presenting: Dave Webb

Energy Imbalance Market
Presenting: Kelcey Brown

Subscriber Solar
Presenting: Bill Comeau

# Case Overview

Case Facts:

- Filed: May 8, 2020
- Test Period: CY 2021 (13-mo avg)
- Rate Effective: January 1, 2021
- Requested Increase: $95.8m (4.8%)
  - Proposed Phase-In Approach:
    - 1/1/21 – 2.6% average increase
    - 1/1/22 – 1.1% average increase
    - 1/1/23 – 1.1% average increase
- Overall Rev. Req: $2.097b (Utah)
- Net Power Costs: $1.421b total
  $618.2m Utah

# Revenue Requirement

- The two major drivers in this case are capital investment since the last general rate case and updated depreciation rates.
- Significant Capital Investments
  - Energy Vision 2020 projects (wind and transmission) and Pryor Mountain - $2.4B
  - Repowering projects - $1.1B, $424m in GRC + $714m in-service by December 2019
  - SCR retrofit projects at Jim Bridger Units 3 ($103m) and 4 ($116m), Craig Unit 2 ($38m), and Hayden Unit 2 ($10m)
  - Conversion of Naughton Unit 3 to natural gas ~$3.2m
  - Various transmission projects ~$558m in additions from January 2020 through December 2021
- *OCS #1 Can RMP provide a preview of any load, or fuel price updates (even qualitative ones if more quantitative work is not available) stemming from the pandemic and the associated economic decline and recovery expectations.*

# Rate Mitigation Proposal

- Use $77.5m of deferred TCJA benefits for the following:
  - Recovery of the 2017 Protocol regulatory asset (13.2m)
  - Recovery of the EIM regulatory asset (9.6m)
  - Recovery of the Carbon regulatory assets (10.3m)
  - Buy-Down the remaining Dave Johnston net book value (23.9m)
  - Recovery of the remaining Deer Creek regulatory assets and liabilities (20.6m)
- Continue Schedule 197 Tax Credit over two year ($44.4m in 2021 and $22.2m in 2022) with remaining deferred TCJA benefits.
- Extend recovery period for Jim Bridger 1&2 until STEP funds accumulate to buy-down remaining plant balance.
- In Docket No. 18-035-36 parties agreed to use STEP regulatory liability balance for specific plant buy downs; using $179.6m to buy down Cholla Unit 4 ($145.9m) and Craig Units 1 & 2 ($33.7m)

# Capital Structure

| Component | $m | % of Total | % Cost | Weighted |
|---|---|---|---|---|
| Long-Term Debt | $ 8,423 | 46.32% | 4.81% | 2.23% |
| Preferred Stock | $ 2 | 0.01% | 6.75% | 0.00% |
| Common Stock Equity | $ 9,759 | 53.67% | 10.20% | 5.47% |
| **Total** | **$18,184** | **100.00%** | | **7.70%** |

- Overall capital structure is presented in the direct testimony of Nikki Kobliha
- Return on equity is presented in the direct testimony of Ann Bulkley

# Major Capital Projects

- Foote Creek Repowering (Direct testimonies of Link and Hemstreet)
  - *OCS #8 Foote Creek I, provide a current update on the status of the project and economics. Also, please discuss any more current analysis of the project in light of the current pandemic situation.*
- Leaning Juniper Repowering (Direct testimonies of Link and Hemstreet)
  - *OCS #7 Leaning Juniper, provide a current update on the status and economics. Also, please discuss any more current analysis of the project in light of the current pandemic situation.*
- Pryor Mountain (Direct testimonies of Link and Van Engelenhoven)
  - *OCS #9 Pryor Mountain, provide a current update on the status of the project and economics. Also, please be prepared to discuss the process by which the Company acquired this project, whether any updated analyses using current data have been performed and whether the Company considered acquiring the project through a competitive bid process at a lower cost.*
- Wind Repowering (Docket No. 17-035-39) (Direct testimony of Hemstreet)
- New Wind and Transmission (Docket No. 17-035-40)
  - Wind (Direct testimony of Hemstreet)
  - Transmission (Direct testimony of Vail)
  - Network Upgrades (Direct testimony of Vail)
- *OCS #2 Regarding the various wind projects, has the pandemic caused any construction delays? Please give a current status of each project including when they will be complete and the Commercial Operation Dates.*

# Major Capital Projects

- Major Transmission Investment Projects (Direct testimony of Vail)
  - Wallula to McNary 230 kV Transmission Line;
  - Snow Goose 500/230 kV Substation;
  - Vantage to Pomona Heights 230 kV Transmission Line;
  - Goshen-Sugarmill-Rigby 161 kV Transmission Line; and
  - Goshen #3 345/161 kV 700 Megavolt-Ampere (“MVA”) Transformer Installation.
- Naughton Unit 3 Natural Gas Conversion (Direct testimony of Van Engelenhoven)
  - *OCS #3 Naughton Gas conversion costs in the current and 2014 test years, current construction status of the project if not yet complete, remaining work to be done, if any.*
- Selective Catalytic Reduction (SCR) retro fit projects (Direct testimony of Owen)
  - Craig Unit 2
  - Hayden Unit 2

# Net Power Costs: Overview

- Net Power Costs (NPC) for 2021 test period was forecasted using the Generation and Regulation Initiative Decision Tool (GRID), a production cost model which serves total system load on a least-cost basis.
- NPC in 2014 GRC was $1,491 million ($25.26/MWh)
  - $628.0 million Utah allocated
- NPC in 2020 GRC is $1,421 million ($23.46/MWh)
  - $619.2 million Utah allocated, an $8.8 million reduction.
- The decrease in NPC is driven by lower coal fuel expense, lower purchased power expense, lower wheeling expense and increased zero-fuel cost renewable generation. The decrease is partially offset by a reduction in wholesale sales revenue and a small increase in natural gas fuel expense.
  - Wholesales sales volumes decreased by 29% and the average market prices of wholesale sales decreased by 17%.
  - Coal generation is 29% lower than the 2014 GRC excluding the impact of Carbon and Cholla 4 coal plant retirements before the test period. The lower coal fuel expense is partially offset by higher coal prices, on average $1.69/MWh higher than 2014 GRC.
- *OCS #10, #11, and #12. Lake Side 2 Unit 3 and Blundell Unit 2 long outages. Causes, costs, and current repair status. RCA study findings. Costs in test year.*

**Net Power Cost Reconciliation**

| | ($ millions) | $/MWh |
|---|---|---|
| **UT GRC 2014** | **$1,491** | **$25.26** |
| Increase/(Decrease) to NPC: | | |
| Wholesale Sales Revenue | 168 | |
| Purchased Power Expense | (6) | |
| Coal Fuel Expense | (248) | |
| Natural Gas Fuel Expense | 19 | |
| Wheeling and Other Expense | (3) | |
| **Total Increase/(Decrease) to NPC** | **(70)** | |
| **UT GRC 2020** | **$1,421** | **$23.46** |

# NPC: Day Ahead/Real Time Adjustment

- DA/RT (Day Ahead Real Time Adjustment) is an adjustment to more accurately capture the costs associated with balancing the system that historically were not captured in GRID.
  - The forward market prices are adjusted to reflect historical variation from average cost of the system balancing purchases and sales and actual market prices on a monthly basis.
  - The system balancing transaction volumes are adjusted to reflect additional system balancing transactions when the Company progresses through balancing its system on a monthly, daily and real-time basis.
  - Better reflects the market prices available to the Company when it transacts in the day ahead and real time markets and better reflects the combination of monthly, daily and hourly products that must be used to balance the system in order to improve the accuracy of NPC forecast.
  - The calculations are based on 48-month average from July 2016 to June 2019.

- *OCS #13 Day Ahead/Real Time Power cost modeling. Information provided in workpapers, OCS 3.7, 3.42. Please be able to discuss the sources of market price data, the calculations performed and the 'hedging activities' modeled in this adjustment in GRID.*

# NPC: Model Validation Benchmark

- PacifiCorp has evaluated and validated its GRID model performance in the past two Oregon Transition Adjustment Mechanism (TAMs) (dockets UE 339 and UE 356) by conducting a backcast or benchmark analysis for the historical periods of 2016 and 2017.
- The validation shows that the variances between the benchmark studies and actual NPC are only 0.03 percent and 0.3 percent for 2016 and 2017, respectively. This implies that the GRID model is capable of reasonably and accurately modeling PacifiCorp's NPC.
    - In the benchmark studies, the following data inputs have been replaced by actual data: load, electricity and natural gas prices, outages and derates, wind and hydro generation, heat rate, and long term contracts (including purchase power agreements and qualifying facilities) generation and prices.
- *OCS #6 GRID Benchmark. Be able to discuss the benchmark that was performed and the availability of documentation.*

# NPC: Other Modeling Changes

- The hourly scalars applied to the official forward price curve (OFPC) are updated to be consistent with the methodology used since the 2017 Integrated Resource Plan (IRP) update
    - CAISO 2-year day ahead prices have replaced Powerdex 5-year hourly prices
- Updated the regulating reserve requirement based on the Flexible Reserve Study in the 2019 IRP
- Included actual capacity factors for owned wind power plants and purchased wind power plants
- Solar generation was shaped by hour according to the 2019 actual generation

# Energy Imbalance Market

- Discuss the Company's treatment of its participation in the Western Energy Imbalance Market ("EIM") and the expected incremental benefits relative to the NPC forecast produced by the GRID model
- *OCS #4 EIM modeling.  Be able to explain the calculations in the provided workpapers, as well as any efforts made by RMP to validate the EIM estimates provided on the CASIO webpage.*
- *OCS #5   Direct Testimony of Gary Hoogeveen states that since its inception in 2014, 9 utilities have joined and 11 more have committed to join the EIM by 2022.  Be able to discuss the status of when the new companies will be joining, how that will impact PacifiCorp, and how that may have been affected the benefits of the EIM that are modeled in GRID.*

# Wildland Fire Mitigation

- As required by HB 66, Rocky Mountain Power filed its Wildland Fire Protection Plan on June 1, 2020.
- For more information on the Wildland Fire Mitigation Plan, a technical conference is scheduled for July 13 as part of Docket No. 20-035-28.
- HB 66 allows the Company to defer and recover the incremental revenue requirement for capital investments needed to implement its wildland fire protection plan, to the extent those investments are not included in base rates.
- Details of the proposed balancing account
- Costs included in the case

# Subscriber Solar

Utah Clean Energy Questions:

- *When customers subscribe to the next round of subscriber solar, is their subscription rate (or any portion of their subscription rate) fixed for a length of time? If so, how long?*
  - The intent is for the Subscriber Solar subscription rate to be fixed for the life of the solar project, adjustments could be made in the future if we add additional projects. The assumption is the addition of future projects would include a blending of the projects and would not increase the subscription rate. An additional project in the future would most likely decrease the subscription rate for all customers due to the program fixed costs are already factored into the proposed program.
- *How have net power costs been considered or incorporated into determination of the Company's proposed new subscriber solar rate?.*
  - The Subscriber Solar resource power purchase agreement and any credit for the value of the energy produced will be situs assigned to Utah customers in net power costs and flow through the Energy Balancing Account
- *How does the Company propose to address rates for subscriber solar customers as subsequent future subscriber solar projects are built? For example, if a 20 MW project were built in 2022, and another 20 MW project were built in 2028 at a lower cost, would the rate for subscriber solar be a blend of the two projects, or would customers of different projects be subject to different rates?*
  - See Response to first bullet.

# Subscriber Solar

Utah Clean Energy Questions:

- *What are the barriers to adapting the subscriber solar tariff to allow owners of affordable multifamily housing buildings to leverage available funding or incentives to reduce the upfront cost of solar, and then pass the energy benefits on to tenants through a subscription?*
  - Response: We already see customers doing this either through the existing subscriber solar program or net metering. Some examples are the GivGroup complex in Salt Lake City, Soleil apartment complex in Herriman and Pamela's Place in Salt Lake City.
- *Please explain how subscriber solar has been made available to multifamily housing complexes who wish to enroll all customers in the building. Does RMP have plans to include a multi-family building component to the new subscriber solar rate to formalize this option?*
  - Response*:* The design for subscriber solar includes participation for multi-family buildings and some are already participating. A recent change was approved for a 100% subscription option that was requested from the multi-family community. We have actively promoted subscriber solar to both apartment tenants and owners. Since the program was designed to include multi-family and is meeting the needs of our multi-family participants there are not any additional formal changes we are requesting.

# Questions?

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