Average wholesale rate projections

Rate pressures and reduction strategies
Discussion

- Overview
- Long-term rate pressure and rate increase scenarios
- Carbon reduction
- Change in rate projection
- Rate drivers
- Strategies to reduce rate pressure
- Recommendation
Overview

• Platte River will continue to proactively work toward the goal of reaching a 100% noncarbon resource mix, while maintaining the three pillars of providing reliable, environmentally responsible and financially sustainable electricity and services.

• **Transition period 2023 to 2029**
  • Significant cost risk in replacing coal portion of resource portfolio that has traditionally provided ~80% of all generation
  • Distributed energy resources integration and collaboration with owner communities
  • Organized energy market participation

• **Post transition 2030 forward**
  • Reduced price risk as ~80% of the resource portfolio is projected to be long-term fixed price contracts
  • Reduced carbon by ~90%
Resource plan update

Resource plan update

- Resource diversification and system integration opportunities, April board materials
- 2020 IRP P2 case refinement to Resource Plan 2022 (RP22),
- Next full IRP scheduled for 2024
- Procurement of new resources by Jan. 1, 2028, instead of Jan. 1, 2030
  - To manage potential delays
  - Planning for reliability
    - Extended dark calm
    - Operational experience prior to retirement of coal-fired generation
  - Updated renewable power purchase agreement cost estimates
- Reduced cumulative carbon emissions ~5.5%
Average wholesale rate

<table>
<thead>
<tr>
<th></th>
<th>2023 preliminary budget</th>
<th>2032 cumulative</th>
</tr>
</thead>
<tbody>
<tr>
<td>Base projections 6.3% (2023 - 2028), 0.0% (2029 – 2032)</td>
<td>6.3%</td>
<td>44.3%</td>
</tr>
<tr>
<td><strong>Revised recommendation</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>5.0% (2023 – 2029), 0% (2030 – 2032)</td>
<td>5.0%</td>
<td>40.7%</td>
</tr>
</tbody>
</table>

- Projections increased from 6.1% (presented to Board in May 2022) to 6.3% based on preliminary budget
- Revised recommendation includes rate pressure reduction strategies to smooth rates over a longer period
- Approval requested by board of directors for 2023 rate increase only

<table>
<thead>
<tr>
<th></th>
<th>2022 budget</th>
<th>2023 preliminary budget</th>
<th>% change</th>
</tr>
</thead>
<tbody>
<tr>
<td>Average wholesale rate *</td>
<td>$64.63</td>
<td>$67.86</td>
<td>5.0%</td>
</tr>
<tr>
<td>Owner community: energy sales (GWh)</td>
<td>3,218</td>
<td>3,301</td>
<td>2.6%</td>
</tr>
<tr>
<td>Owner community: revenues (Millions)</td>
<td>$208</td>
<td>$224</td>
<td>7.7%</td>
</tr>
</tbody>
</table>

*Based on projected owner community energy and demand forecasts as well as forecasted intermittent energy production.
Long-term rate pressure reduction strategy

- RP22 creates higher rate pressure over a shorter period followed by a period with no pressure
- Strategies to reduce rate pressure
Change in rate projection
Evolving projections

• 2032: Current projections vs. May 2021 projections
  • Expenses ~16% higher
  • Rates ~8% higher
    • Rates lower due to higher assumed owner community loads partially from beneficial electrification

• Significant assumption updates since May 2021
  • RP22 is provisional resource case following the 2020 IRP, prior to 2024 IRP
  • Asset integration schedule acceleration
  • Renewal resource cost estimates increased
  • Dispatchable thermal firm transportation cost estimates
  • Portion of Rawhide Energy Station’s fixed operations and maintenance expense assumed to continue post coal-fired unit retirement
  • Staffing increased to support organized energy market entry, DER and technology
  • WAPA hydropower energy reduction and rate increase
Modeling uncertainties

Potential modeling assumptions changes include, but are not limited to the following (this is why we revisit this multiple times per year and only request direction for the following year, the rest is an indication):

- Asset integration schedule
- Capital forecast
- Coal inventory sales
- Commodity prices
- Decommissioning
- DER strategy
- Economic externalities
- Emissions expense
- Federal hydropower allocations
- Integrated Resource Plan
- Load forecast
- Organized energy markets
- Pandemic
- Resource diversification policy
- Staffing
- Surplus sales
Rate drivers
Owner community revenue requirement

- Owner community revenue requirement is reduced by surplus sales revenue
- Revenue requirement increasing $138 million
  - $103 million, 75%, is cost increase
  - $80 million, 78%, of cost increase due to resource transition (significant risk)
  - $24 million, 22%, of cost increase across multiple cost categories
  - $35 million, 25%, is surplus sales reduction
- ~90% carbon emissions reduction
Operating and finance expenses

- Asset integration schedule and projected cost increases for renewable energy are driving rate pressure

*$Other includes depreciation, amortization and accretion, interest expense and other income
Generation asset transition

Cost to transition remaining coal generation increasing by $80 million

- 2022
  - 2,412 dispatchable thermal, $30/MWh, $72.9 million
- 2032
  - 2,412 dispatchable thermal, wind, solar, storage, $63/MWh, $153 million
    - 357 GWh dispatchable, $125/MWh, $44 million
    - 1,056 GWh, wind, $47/MWh, $50 million
    - 999 GWh solar, $32/MWh, $32 million
    - Storage, $26 million

New resources have significant cost uncertainty

- E.g., next solar installation is likely to increase ~$7 million per year from current projections
Carbon emissions reduction

Reductions:
- ~90% 2023 – 2032
- ~5.5% RP21 to RP22
Strategies to reduce rate pressure
Strategies to reduce rate pressure

• Strategies to explore
  • Accounting deferral policy
  • Windy Gap water unit sales
  • Prepay power purchase agreements

• Strategies that are not optimal
  • Delay asset integration schedule
  • Ownership vs. power purchase agreements
  • Additional debt financings
Strategies to reduce rate pressure

Strategies to explore
What is an accounting deferral policy?

• Defers a portion of revenues from strong financial years to be recognized in future years when rate pressure occurs
• Defers a portion of expenses during transition period to future years with less rate pressure
• Consistent with other board approved accounting policies that spread costs for rate making purposes
  • Pension contribution expense recognition policy
  • Maintenance outage expense accrual policy

How will it be used?

• To be structured for use only during the resource portfolio transition with flexibility to adapt as the transition plan becomes finalized
• Ensures SFP minimum financial metrics are met
• Purpose is not to avoid needed rate increases but rather to avoid raising rates higher than necessary for years following the generation portfolio transition
Deferred revenue example

Actual revenues vs revenue requirement

- Defer portion revenues above requirement
- Recognize deferred revenues to fill deficiency

- SFP owner community revenue requirement
- Actual owner community revenues (5.1% increases thru 2028)
Deferred expenses example

- Projected expenses with deferral
- Projected expenses

Defer defined expenses
Recognize deferred expenses to period with less rate pressure
Deferred accounting policy

- Increased rate flexibility and adaptability with evolving asset integration costs and timing
- Reduces rate pressure during the resource transition plan period with greater long-term rate stability
- Aligns with the boards’ preference to smooth rates, avoiding significant single year increases
- Lowers total rate pressure, enhancing Platte River’s rate competitiveness
- No expected credit rating impact
- Limit deferral of expenses to avoid shifting too much burden to future years
- Lower rates results in lower cash flow, increasing debt issuance
Deferred accounting policy

- RP22 creates more rate pressure over a shorter period; followed by a period with no pressure
- Deferred accounting policy
  - Lowers RP22 rate pressure to 2028 approximately 7% and total pressure approximately 3%
  - Smoother rate trajectory; followed by a period with no rate pressure
Windy Gap water unit sales

- Prior sales already mitigating rate increases
  - Reduces rates ~5%
- Total proceeds of $102.9 million received
  - 2023 – 2029 $11.0 million gain recognized annually, incorporated into projections
  - Increases cash reserves, lowering future debt requirements
  - 50 units sold of 60 units available to sell
- Potential 2022 sale of five units
  - Proceeds would be factored into projections
  - Cash from sale will facilitate financing resource additions, reducing debt issuance projections, positively impacting rates
Prepay power purchase agreements

• Based on natural gas prepay structures
• Estimated savings ~7% of purchase power agreement, however
  • Long-term benefits unknown at time of agreement (resets periodically)
  • Power purchase agreement term and prepayment term do not align
    • Risk of prepayment agreement without a power purchase agreement
• Rate impact, and resulting savings, dependent on quantity of prepay structured renewable contracts
• Additional analysis and legal review required
Strategies to reduce rate pressure

Strategies that are not optimal
Delay asset integration schedule

- Significant cost increases projected in 2027 ($8.4 million) and 2028 ($26.0 million) as renewable and storage resources are added.
- Modeled costs could be updated to integrate resources later (mid 2028 or 2029).
- Asset integration schedule timing is based on enhancing reliability and reliability is at risk if the integration schedule is changed.
  - Accounting deferrals also shift expenses without impacting reliability.
- Annual rate projections will change but total rate pressure of resource transition is not impacted.
Ownership vs. power purchase agreements

- Independent Power Producers and Investor Owner Utilities can utilize accelerated depreciation and federal tax subsidies to lower costs 15-20%.
- Renewable developer’s competitive advantage with EPC costs, manufacturing, and O&M is confidential information:
  - Cost savings vary by developers, approximately 5-10%.
- Renewable developers pass along a portion of these advantages in PPA pricing to be competitive.

Source: Lazard’s levelized cost of energy analysis—version 15.0, 28th October 2021
Cash and debt

- SFP provides structure to balance cash and debt to finance dispatchable resources, transmission and other capital investments
- Ability to issue more debt, but does not provide rate relief rather creates more rate pressure
Recommendation

• Implement deferred accounting policy
• 5.0% rate increase for 2023
  • Long-term projections: 5.0% 2023 – 2029, 0.0% 2030 – 2032
  • Significant changes to long-term projections are likely
• Ongoing activities
  • Update resource plan and rate forecast annually (continuously evolving)
    • Continued DER collaboration among Platte River and the owner communities
  • Continue to evaluate options to reduce rate pressure
    • Windy Gap water unit sales
    • Prepaid power purchase agreements
Questions
Foundational DER implementation

Raj Singam Setti, chief transition and integration officer
Building a strong foundation for DER implementation

- DER services: 2 Years
- DER transition and integration: 2 – 3 Years
- DER infrastructure: 2 – 3 Years
- Grid infrastructure

System impact, pilots, monitor: 2 – 3 Years
Markets, distribution system operation: 2 Years
Implementation objectives

Objective 1: Utility data and telemetry
- Meter infrastructure (AMI)
- Meter data management system (MDMS)
- Real Time Data communications, quality, and cybersecurity

Objective 2: Process and integration
- DER checklist
- DER Interconnection
- Compensation & rates

Objective 3: DER enabling system
- Operational technologies (OT)
- Advanced Distribution management system, Energy management system (ADMS/EMS)
- Distributed energy resource management systems (DERMS)

Objective 4: Customer centric engagement
- Customer value proposition
- Customer adoption modeling
- Customer programs, energy community

Objective 5: Enhanced situational awareness
- Monitor and control
- Grid constraints
- Reliability
Questions
Board of directors

July 28, 2022
Market selection

Melie Vincent, chief operating officer
Agenda

• Market options evaluated
• Key aspects
• Southwest Power Pool Western Energy Imbalance Service (SPP WEIS)
• SPP Markets+ and the Western Markets Exploratory Group (WMEG)
• Southwest Power Pool Regional Transmission Organization West (SPP RTOW)
• Market option comparisons
• Markets timeline
Market options under consideration

- SPP WEIS
  - Platte River committed to join in April 2023
- SPP Markets+ and WMEG
  - Market formation and pricing discussions are ongoing
  - Unknown if or when this would become a viable market option
- SPP RTO West
  - Platte River could join April 2025
Key aspects of long-term market solution

• Generator unit commitment
• Regional transmission planning
• Optimal dispatch of available resources
• Large geographic footprint to ensure intermittent resources are efficiently dispatched
• Regional entity responsible for reliability
• Market products that enable appropriate monetization of resource assets, including DER
• Robust and effective governance structure
## Comparison of market services and products

<table>
<thead>
<tr>
<th>Key aspects</th>
<th>SPP WEIS</th>
<th>SPP Markets+</th>
<th>WMEG</th>
<th>SPP RTOW</th>
</tr>
</thead>
<tbody>
<tr>
<td>Generator unit commitment</td>
<td>None</td>
<td>Likely</td>
<td>Likely</td>
<td>Yes</td>
</tr>
<tr>
<td>Optimal dispatch of available resources</td>
<td>Only online resources in real-time (RT)</td>
<td>Day-ahead (DA) transmission (XMSN) compensation may result in diverging day-ahead and real-time market prices</td>
<td>DA XMSN compensation may result in diverging day-ahead and real-time market prices</td>
<td>Yes, in both DA and RT</td>
</tr>
<tr>
<td>Congestion hedging</td>
<td>None</td>
<td>Likely RT only</td>
<td>Likely RT only</td>
<td>Yes</td>
</tr>
<tr>
<td>Optimization of ancillary services</td>
<td>None</td>
<td>Unknown</td>
<td>Unknown</td>
<td>Yes</td>
</tr>
<tr>
<td>Regional transmission planning</td>
<td>None</td>
<td>Unlikely</td>
<td>Unlikely</td>
<td>Yes</td>
</tr>
<tr>
<td>Large geographic footprint to ensure efficient dispatch of intermittent resources</td>
<td>Limited footprint</td>
<td>Unknown</td>
<td>Unknown</td>
<td>Limited footprint</td>
</tr>
<tr>
<td>Regional entity responsible for reliability</td>
<td>None</td>
<td>Unlikely</td>
<td>Unlikely</td>
<td>Yes</td>
</tr>
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</table>
## Comparison of market key risks

<table>
<thead>
<tr>
<th>Key risks</th>
<th>SPP WEIS</th>
<th>SPP Markets+</th>
<th>WMEG</th>
<th>SPP RTOW</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Long-term certainty</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>• SPP Markets+ or WMEG may replace WEIS</td>
<td></td>
<td>1. SPP Markets+ may not materialize</td>
<td>1. WMEG may not materialize</td>
<td>1. WAPA needs to join and remain a XMSN owning member (TOM)</td>
</tr>
<tr>
<td>• SPP Markets+ may not materialize</td>
<td>2. Could be replaced by an RTO market</td>
<td>2. Could be replaced by an RTO market</td>
<td>2. Could be replaced by an RTO market</td>
<td>2. Long-term success depends on attracting additional TOMs</td>
</tr>
<tr>
<td><strong>Operational concerns</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1. Interim solution only</td>
<td></td>
<td>1. Interim solution only prior to an RTO</td>
<td>1. Interim solution only prior to an RTO</td>
<td>• Others may join RTOW under more favorable terms in the future</td>
</tr>
<tr>
<td>2. Does not provide a path to a full RTO</td>
<td></td>
<td>2. New market with new processes and systems</td>
<td>2. New market with new processes and systems</td>
<td></td>
</tr>
<tr>
<td><strong>Platte River's share of market start-up costs</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>• Given the elimination of JDA, Platte River is committed to join SPP WEIS by April 2023</td>
<td></td>
<td>1. Share of market start-up likely $2-4M, assuming 20-30 GW of load joins</td>
<td>1. Share of market start-up likely $2-4M, assuming 20-30 GW of load joins</td>
<td>• Market start-up costs will not result in a separate fee to RTOW participants, as such costs will be recovered by SPP in admin fees</td>
</tr>
<tr>
<td>• Platte River is committed to join SPP WEIS by April 2023</td>
<td>2. Additional internal costs to allow participation</td>
<td>2. Additional internal costs to allow participation</td>
<td>2. Additional internal costs to allow participation</td>
<td></td>
</tr>
<tr>
<td>• Platte River is committed to join SPP WEIS by April 2023</td>
<td>3. Additional start-up and internal costs to join RTO in the future</td>
<td>3. Additional start-up and internal costs to join RTO in the future</td>
<td>3. Additional start-up and internal costs to join RTO in the future</td>
<td></td>
</tr>
<tr>
<td><strong>Exit fees to join a more favorable market</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>• None, with a two-year commitment</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>• Likely required to provide notice and pay unamortized start-up costs</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Exit fees to join a more favorable market</strong></td>
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<td>• None, with a two-year commitment</td>
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<td>• Likely required to provide notice and pay unamortized start-up costs</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Exit fees to join a more favorable market</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
# Market option comparison – costs

<table>
<thead>
<tr>
<th>Estimated annual cost savings</th>
<th>SPP WEIS (Xcel Energy BA)</th>
<th>SPP Markets+</th>
<th>WMEG</th>
<th>SPP RTOW**</th>
</tr>
</thead>
<tbody>
<tr>
<td>Incremental transmission costs (savings)</td>
<td>$0</td>
<td></td>
<td></td>
<td>($3,666,162)</td>
</tr>
<tr>
<td>Schedule 1 (scheduling &amp; dispatch)</td>
<td>$319,003</td>
<td></td>
<td></td>
<td>$319,003</td>
</tr>
<tr>
<td>Schedule 3 (regulation &amp; frequency)</td>
<td>$1,002,641</td>
<td></td>
<td></td>
<td>$1,002,641</td>
</tr>
<tr>
<td>Schedule 5 (spinning reserves)</td>
<td>$994,694</td>
<td></td>
<td></td>
<td>$994,694</td>
</tr>
<tr>
<td>Schedule 6 (operating reserves)</td>
<td>$255,436</td>
<td></td>
<td></td>
<td>$255,436</td>
</tr>
<tr>
<td>Schedule 16 (flex reserves) (*)</td>
<td>$2,354,306</td>
<td></td>
<td></td>
<td>$-</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>$4,926,080</td>
<td></td>
<td></td>
<td>($1,094,388)</td>
</tr>
</tbody>
</table>

* Flex reserves annual cost based on 2022 FERC settlement less $500,000 per year savings resulting from self-supply

** For purposes of this comparison, SPP RTO West Schedule 1, 3, 5, 16 & 16 charges are assumed equal to SPP RTO charges
SPP RTOW

Benefits

- SPP WEIS, SPP Markets+ and WMEG benefits
- Centralized transmission planning
- Proven market rules and processes used in other RTOs
- Greater certainty when planning for future resources
- Expands options for placement of future Platte River resources

Limitations

- 100% of the cost of new transmission facilities greater than 300 kV is allocated on a load ratio share basis
- 33% of the cost of transmission facilities ranging between 100 kV and 300 kV are allocated on a load ratio share basis
- Generator interconnection and firm transmission service requests will be performed by SPP, and Platte River would have little, if any, influence on the schedule to evaluate these requests
  - Possible mitigation: Interconnection requests in Platte River’s queue prior to joining an RTO would continue to be evaluated by Platte River
### Markets integration timeline

<table>
<thead>
<tr>
<th>Timeline</th>
<th>Task</th>
</tr>
</thead>
<tbody>
<tr>
<td>Q1 2022</td>
<td>• Platte River, PSCo and BHE committed to join SPP WEIS</td>
</tr>
</tbody>
</table>
| Q3 2022 | • Review draft service offering of SPP Markets+ and WMEG  
          • Review cost/benefit studies of various markets  
          • Select preferred market option |
| Q2 2023 | • Begin participating in SPP WEIS  
          • Financially commit to join SPP RTOW |
| Q2 2025 | • Begin participating in SPP RTOW |
| Q1 2028 | • Earliest time SPP Markets+ or WMEG would be operational |
Key points

- SPP WEIS is a real-time only market that will serve as a bridge market solution to a full RTO.
- Platte River intends to financially commit to SPP RTOW in early 2023.
- Staff expects SPP RTOW will result in significant transmission and ancillary service cost savings.
- Committing to SPP RTOW will create certainty for Platte River resource planning, DER development and transmission investment decisions, a critical aspect of the Resource Diversification Policy.
- Staff will review market mechanisms, opportunities and hedging strategies unique to RTO participation with the board in future meetings.
Questions
## May and June operational results

<table>
<thead>
<tr>
<th>Category</th>
<th>May variance</th>
<th>June variance</th>
<th>YTD variance</th>
</tr>
</thead>
<tbody>
<tr>
<td>Owner community demand</td>
<td>1.6%</td>
<td>6.4%</td>
<td>4.2%</td>
</tr>
<tr>
<td>Owner community energy</td>
<td>(1.2%)</td>
<td>2.0%</td>
<td>0.5%</td>
</tr>
<tr>
<td>Wind generation</td>
<td>18.7%</td>
<td>14.8%</td>
<td>8.6%</td>
</tr>
<tr>
<td>Solar generation</td>
<td>2.8%</td>
<td>9.7%</td>
<td>8.7%</td>
</tr>
<tr>
<td>Net variable cost to serve owner community load*</td>
<td>30.3%</td>
<td>29.1%</td>
<td>10.3%</td>
</tr>
</tbody>
</table>

Variance key:  Favorable: ● >2%  |  Near budget: ◆ +/- 2%  |  Unfavorable: □ <2%

*Total resource variable costs plus purchased power costs less sales revenue
## Financial summary

<table>
<thead>
<tr>
<th>Category</th>
<th>May variance from budget ($ in millions)</th>
<th>June variance from budget ($ in millions)</th>
<th>Year to date variance from budget ($ in millions)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Net income *</td>
<td>$2.5</td>
<td>$2.8</td>
<td>$6.1</td>
</tr>
<tr>
<td>Fixed obligation charge coverage</td>
<td>.61x</td>
<td>1.37x</td>
<td>.56x</td>
</tr>
<tr>
<td>Revenues</td>
<td>$2.0</td>
<td>$2.5</td>
<td>$6.5</td>
</tr>
<tr>
<td>Operating expenses</td>
<td>$(0.1)</td>
<td>$1.2</td>
<td>$3.9</td>
</tr>
<tr>
<td>Capital additions</td>
<td>$0.8</td>
<td>$1.4</td>
<td>$12.6</td>
</tr>
</tbody>
</table>

2% ● Favorable  | 2% to -2% ◆ At or near budget | < -2% ■ Unfavorable

* Net Income results impacted by unrealized losses on investments, $0.7 million in April and $3.9 million year to date
Board of directors

July 28, 2022