Board of Directors
Regular Meeting

Tuesday, November 30, 2021
Virtual Meeting via Zoom

The OPALCO Board of Directors are following CDC and San Juan County guidelines for social distancing and all OPALCO public gatherings are cancelled until further notice in order to err on the side of caution in face of tremendous uncertainty with the current pandemic. Board meetings will be conducted as scheduled via remote video conferencing until further notice.

Members may participate in the regular board meetings via Zoom. The first part of the meeting is reserved for member questions and comments. Use the chat feature on Zoom and staff will respond as soon as possible following the meeting. Please follow the protocols listed below:

- Mute yourself unless talking,
- Use your first and last name in your Zoom identity,
- Chat if you have a question/comment and the monitor will put you in the queue,
- OPALCO's Policy 17 - Member Participation at OPALCO Meetings decorum must be followed.

The Zoom link will be updated monthly and published in the board materials the Monday before each meeting. The link for this meeting is:

Meeting URL: https://opalco.zoom.us/j/86576474100

Meeting ID: 865 7647 4100

Members may also submit any comments and questions in writing no less than 24 hours in advance of each meeting to: communications@opalco.com

Sequence of Events

- OPALCO Board Meeting
- Executive Session

OPALCO
Co-op Run. Community Powered.

Board of Directors
Regular Board Meeting
November 30, 2021 8:30 A.M.*
Virtual Meeting via Zoom

**Time is approximate; if all Board members are present, the meeting may begin earlier or later than advertised. The Board President has the authority to modify the sequence of the agenda.*

WELCOME GUESTS/MEMBERS

Members attending the board meeting acknowledge that they may be recorded, and the recording posted to OPALCO's website. Members are expected to conduct themselves with civility and decorum, consistent with Member Service Policy 17. If you would like answers to specific questions, please email communications@opalco.com for post-meeting follow-up.

Agenda

EXECUTIVE SESSION
- Legal, Personnel, Competitive, Other

ADJOURNMENT

ACTION ITEMS

Consent Agenda

All matters listed with the Consent Agenda are considered routine and will be enacted by one motion of the Board with no separate discussion. If separate discussion is desired, that item may be removed from the Consent Agenda and placed as an Action Item by request of a Board member.

The Consent Agenda includes:

- **Minutes** of the previous meeting – attached.
- **Approval of New Members** – attached {as required by Bylaws Article I Section 2 (d)}

NEW MEMBERS – October 2021

District 1 (San Juan, Pearl, Henry, Brown, Spieden)

AMOS, BRYON
BEAIRD, TRACY
BITZ, CECILIA
BLACKBURN, JESSICA & GARCIA, CARLOS
BOYCE, BARRY
BOYLE, JOHN & BOYLE, LAURA
BRAGG, KEVIN & TSCHIRHART, LAUREN
BRANDT, RION & KERNS, SAVANNAH
CAMPOS, SAVANNAH
CASON, DANIEL
CONANT, MICHAEL
COOKE, MICHAEL & COOKE, ANN
CULLUM, LISA
ERICKSON, CHAD & SROKA, NICOLE
FREEMAN, ERINN
GATLEY, BRUCE
HARDWICK, JESSE
HEGLAR, JON
HENRY, JENNIFER
HEYING, HEATHER
HILDRETH, KIMBERLY
ILVONEN, TINA
JENSEN, JOSHUA
JOHNSON, DARYL
JOHNSON, THOMAS
KASEY, MARGARET
LEE, HEATHER
LUNDSGAARD, MELISSA & LUNDSGAARD, ROB
MARTIN, DONNA
MARTINEZ, DARCEY
MATTSON, CARLY
MAVERICKS LN WELL
MERCER, GERALD & MERCER, DEBRA
MIDDLEBROOKS, ANTHONY
NEELY, MOLLY & WALKER, RICHARD
OATES, RICHARD
OVSEPIAN, STEPHAN & RODRIGUEZ, RUBY
PBC PAYMASTER LLC
PHILLIPS, WYATT
RHUDE, STINA
ROBBINS, LEE & WHITE, KIRSTEN
RUYLE, JUSTIN
SANTIAGO, ERIKA & LUNA, HECTOR
SCARBERRY, JEFF
SISSON, JODI & SISSION, SCOTT
SMITH, KARA
SOLAN, ALTA
STARSHINE, SUE
STEPHENS, ANTHONY
STOCKSETT, ANGELA
TURLEY, LESLIE
VAN DYCK, MICHAEL
VANLIEU, MICHELLE
WADE, WILLIAM
WAGENBACH, MICHAEL & WORDEMAN, LINDA
WEBER, MARIAN
WILDE, BETTIE & OLSON, GREG
WILLIAMS, KEN & WILLIAMS, ROBERTA
WILSON, CHRISTAL

District 2 (Orcas, Armitage, Blakely, Obstruction, Double, Alegria, Fawn)

ABEL, JEREMY
ALLAN, THOMAS & ALLAN, ANNE
AROUXET, CASSONDRA & AROUXET, GILLES
AVERNA, NATE & AVERNA, HAILEY
BODEN, DAINA & KRAMER, BILL
BRADSHAW, JASON & BRADSHAW, ANNA
CROUZIER, WELLESLEY
DAVIDSON, GRETCHEN
DENNIS, HOLLY
IRT OF EMILY DEE, ANN TYSON
JOHNSON, MICHAEL
KONING, ERIN
MARKPEAK ASSOCIAT, ES LLC
MCCARTY, JANET
MEISSNER, ALEXA & MEISSNER, CHARLES
MULVANY, BURKE
NELSON, HILARY & NELSON, NATE
NGUYEN, HOLLY
NIELSEN, ABIGAIL
OSTLE, HEATHER
READEY, MICHAEL & READEY, MARY BETH
ROGERS, CAMERON
SALISH SEA YARN CO LLC
SCHURGER, MELISSA
SORENSEN, RACHEL & BOYDSTON, GALEN
STANSBURY, HEATHER
STREETER, JENNIFER

SUNG, EUGENE & LANDAU, ELIZABETH
TAYLOR, CARISSA & TAYLOR, ROBERT
THISTLE LANE, LLC
VICTORIANO, JUAN C
WILSON, DONALD
WOODWARD, ROBIN

District 3 (Lopez, Center, Decatur, Charles)

BUCHANAN, SANDRA
COLGROVE, STEVE
FAY, JONATHAN & FAY, KAREN
JOHNSON, STEVEN
KROLL, MARLA
LEARNED, AMBER & MILLER, DAMIAN
LENZ, CYNTHIA & LENZ, DOUGLAS
MANSFIELD, LARISSA & PEDERSEN, MARK
MEIER, ERIC
MITCHELL, VALERIE
MUKASHI MUKASHI LLC
OCHILTRE, JAMES
REID-ALLEN, KAREN & ALLEN, CRAIG
ROBINSON, CAROL
ROGERS, JOHN & ROGERS, CATHERINE
ROTH, KAREN
SAILLE, LORI
STORMY PINES LLC
TIPTON, BRADFORD
VIRGIL & DESK TRU, ST

District 4 (Shaw, Crane, Canoe, Bell)

BYERS, KEVIN & ALDRICH, REBECCA
MKNK 2020 HOLDINGS LLC

- Capital Credit payments to estates of deceased members and/or organizations no longer in business as shown below:

November

Customer #	Amount
70336	574.69
Total	**$ 574.69**

Staff requests a motion to approve the Consent Agenda.

Orcas Power & Light Cooperative
Minutes of the Board of Directors Meeting
Thursday, October 21, 2021

Streaming through Zoom attendees were: President Vince Dauciunas, Board members Rick Christmas, Jerry Whitfield, Brian Silverstein, Mark Madsen, Tom Osterman and Jeff Struthers. Staff present were General Manager Foster Hildreth; Manager of Engineering and Operations Russell Guerry; Manager of Finance and Member Services Nancy Loomis; Public Relations Administrator Suzanne Olson; Communications Specialist Krista Bouchey; Head Accountant Travis Neal, and Executive Assistant Kelly Koral (serving as recording secretary). Also present were Legal Counsel Joel Paisner and consultant Jay Kimball.

Member comment session commenced at 8:30 a.m.

Members in attendance:

Bruce Nyden	Angela Morrison	Richard Strachan
Justin Wolfe	Sandy Bishop	Bill Will, WA Solar Energy Industries
Chris Wolfe	Janet Alderton	Rick Fant
Elliot Burch	Andey Finley	Barbara Rosenkotter
Sharon Abreu	Heather Nicholson	Chris Greacen
Scott Finley	Chom Greacen	Susan Bauer

Guests:
John Prescott
Anita Decker

Krista welcomed all to the meeting. Asking guests to type in any questions to the chat feature during the member comment period now. Reviewed today's agenda, shared details of her EV road trip around Washington, explained it's National Co-op month, OPALCO is hiring apprentice lineman, OPALCO needs EGC volunteers and reminded all storm season is here.

MEMBER COMMENTS:
Members in attendance shared their thoughts on the proposed changes to solar rates.

President Vince Dauciunas opened the meeting and thank everyone for their comments. Agenda will be changed to accommodate guests who will be joining at 11:00 a.m.

CONSENT AGENDA

> **MOTION** was made to accept the consent agenda by Madsen. Seconded by Struthers. Passed unanimously by voice vote.

CAPITAL CREDITS ALLOCATION (Final Read)

> **MOTION** to adopt the revisions to Member Policy Services 11 as amended so non-electrical revenue does not count in OPALCO's capital credit allocation. Motion made by Struthers, second by Silverstein. Passed by unanimous voice vote.

SOLAR RATE DISCUSSION
GM presented and stated the goal is to encourage as much renewable generation as possible but there is a need to balance competing restraints. Discussion was held by the Directors. Members were encouraged to share their thoughts by emailing Communications@opalco.com. It was agreed an energy roundtable would be scheduled for members to participate in before final decisions would be made.

Break 9:53 a.m.
Back 10:07 a.m.

EIGHTH POWER PLAN
Guests from the Northwest Power and Conservation Council were unable to attend the meeting as hoped. They will attend an OPALO board meeting at a later date.

COVID UPDATE
Current information was reviewed.

GM REPORT
The GM report was reviewed.

SOLAR INCENTIVES
Discussion held about how to assist low to medium income members.

End of Regular Session 11:00 a.m.

EXECUTIVE SESSION 11:00 a.m.

Back to regular session 12:50 p.m.

> **MOTION** made by Madsen to approve submittal of Form 990. Second by Silverstein, approved by unanimous voice vote.
>
> **MOTION** made by Madsen to approve Rick Fant as a member of the Elections and Governance Committee (EGC). Second by Whitfield. Passed by unanimous voice vote.

_______________________________________ _________________________________

Vince Dauciunas, President Brian Silverstein, Secretary/Treasurer

Special Retirement to Uncollectible Accounts

As is the routine practice each year, staff has transferred delinquent inactive accounts to an uncollectable account (UA) status. The next step in this process is to proportionately apply previously allocated member capital credits to UA balances. Note: These accounts do not impact any active accounts or members on payment arrangement plans (i.e., caused by pandemic).

It is important to note that our billing software 'flags' accounts and associated capital credit payment processes when member accounts are transferred to the status of uncollectable. When staff processes the year-end check run to pay allocated member capital credits, our software will first pay uncollectable account balances before issuing a capital credit check for any remaining balance.

Staff is requesting that $5,967.01 of member capital credits be applied to UA balances. The member capital credit allocation transfers are as follows:

Capital Credits Applied to UA Balance	$5,967.01
Discounted Capital Credits Remain in Equity	$28,278.72
Total Capital Credits Retired	$34,245.73

Staff recommends the board make a motion to approve the use of member allocated capital credits to reduce and/or offset individual member delinquent UA balances as referenced in the Capital Credit /Bad Debt Payment Program report.

General Retirement

The purpose of this memorandum is to obtain Board approval to fund the general retirement of capital credits. Capital Credit distribution is especially important this year as the membership has been impacted by the COVID-19 pandemic and many are struggling financially. More than ever, the cooperative benefits demonstrated by capital credits and OPALCO's concern for community are critical to communicate through this general retirement. Please note staff is continuing with the concept of smoothing, whereby we fund the remaining unretired balance from 1996 and a portion of 1997 as follows.

Year (% of unretired)	Retirement	Projected Checks
1996 (~100%)	$395,130	~$307,000
1997 (~66%)	$904,870	~$702,000
Total	**$1,300,000**	**~$1,009,000**

The difference between the Retirement and Projected Checks above are individual members who in most cases have inactive accounts, moved out of the service territory and have not updated their contact information.

This will continue our 25-year retirement rotation and capital credit retirement smoothing methodology established by the board in December 2017. As a reminder, smoothing the annual general retirements produces a predictable schedule that will allow us to not only stay ahead of the 25-year retirement schedule, but also avoid fluctuations in margins, cash and equity stemming from capital credits.

Staff is requesting a motion to approve the payment and retirement of capital credits for the remainder of 1996 and a portion of 1997, as outlined above.

Solar Rates Review

Timeline:

✓	May 5	Solar Town Hall
✓	May 20	Member Generation Trends and Modeling
✓	June 17	Internal Staff Review
✓	August 19	Guernsey review of alternatives
✓	September 16	Impact on co-op members (low-income, low-use, high-use, etc.)
✓	September 20	Solar Town Hall – member feedback
✓	October 21	Solar Town Hall Recap, Policy and Tariff Structure Proposal (first read)
✓	November 2	Energy Roundtable Member Discussion
	November 30	Energy Roundtable Recap; Renewable Generator Rate Structure Approval
	December 16	Policy and Tariff Structure Adoption (second read)
	January 1, 2022	Implementation of 2022 Tariffs
	March 31	Deadline to opt out of new tariff

OPALCO set out in early 2021 to study how solar rates were performing based on the Co-op's cost of service model. There were several issues exposed: 1) solar rates are documented in Policy 13 and need to have a tariff in place; 2) the current rate structure is not collecting enough revenue through kWh usage to pay for the use of the grid (solar producers use the grid to buy and sell power); and 3) solar production is increasing ~30% each year on OPALCO's system, which will compound the issue of revenue collection over the coming years. The Co-op must also address the fundamental flaw in how much of its revenue is collected through power sales.

> **Fundamental Flaw***:* The utility industry is historically set up to collect revenue based on how much power they sell. This puts utilities in conflict when they encourage their consumers to buy less power and generate power themselves (i.e., conservation, efficiency, member generation). As a nonprofit co-op it is essential to cover our costs. As OPALCO members adopt these measures and use less power, the co-op must shift the paradigm on rates to collect enough money to operate. Because OPALCO embraces and encourages conservation, efficiency and locally generated power, the revenue model has to change.

In early 2021, OPALCO completed a rate analysis to review how solar rates were meeting our cost-of-service mandate. Co-ops operate at the cost of service, which means everyone pays their fair share of the cost to deliver power. Staff tested several solar rate models and developed a draft proposal for board review in October. The proposal has two key components: 1) changes to the banking mechanism from kWh on an annual basis to dollars on a monthly basis; and 2) changes the rate OPALCO pays solar producers/member generators from retail ($0.1089) to an adjusted rate of $0.0849 which includes a charge for use of the grid and a credit for avoided transmission cost and a renewable premium for the value member generators bring to the grid.

This adjustment DOES NOT FIX the problem of uncollected revenue. OPALCO will be separating these topics in two unique efforts and solving them independently. The fundamental problem with collecting revenue through energy (kWh) sales (and encouraging members not to use kWh via energy efficiency and renewables) will be addressed separately and over time. The solar discussion started with a goal to put a value on use of the grid: to add a small grid charge to the solar rate when member generators over-generate and use the grid as storage – putting kWh back on the grid. The new tariff begins the process of improving the balance in the rate structure; it recognizes the value solar producers bring to the utility while collecting more of the costs that solar producers incur with their increased use of the grid. The true correction is anticipated around the year 2030 when:

- OPALCO will have negotiated a new contract with Bonneville Power Administration for power purchases (2028);
- Decarbonization mandates will be in place (WA CETA legislation);
- Wholesale power costs are forecast to be higher in the region as resources shift to renewable;
- Solar costs are forecast to be level or lower than wholesale power; and
- New price signals will result from time of use, time of generation, peak and demand charges.

There is no question that the problem of revenue collection is impacting the Cooperative's finances and that the impact will compound over time. The Board must decide the timeline for improving the rate structure, what mechanisms to put into place for that correction – and address the fundamental flaw in the residential and commercial rate structures for collecting more of the true cost of service in the service access fee. We know a paradigm shift is upon us and as a cooperative we must decide the timing of how to implement the fix: in phases or wait for the price signals and consequences to accelerate.

Local energy production is an important part of OPALCO's Integrated Resource Plan, and the Co-op supports sustainable development of member generation in the islands. OPALCO cares and is committed to being good stewards of our pristine island environment. These Co-op actions directly support the health of our sensitive marine environment and local species:

- Clean air and water: encouraging members to switch to electric vehicles and providing incentives
- Reduce demand for power: incentives and financing to help members make their homes/businesses energy efficient
- Decrease dependency on mainland power: building small, local microgrids (solar with energy storage)
- Reduce vessel noise: lobbying WSF to get hybrid-electric ferries on our San Juan Islands routes before their scheduled time in 2040

At the October meeting, the Board heard from members and encouraged additional member feedback at an Energy Roundtable, which was held on November 2. Member feedback that was collected is presented below (in Member Feedback section) and in the Appendix.

Solar Advocacy:

OPALCO is a longtime advocate for conservation and renewable generation locally and is viewed by their peers as a leader in the region. OPALCO will increase its efforts to tell members about the multiple ways and programs available to support local renewable energy. As outlined in the OPALCO IRP, local renewables and conservation are integral portion of the energy future of our cooperative.

Included in the 2022 Budget is a section for increasing support for local renewable programs, as outlined below. New programs will be developed throughout 2022, with input from members, to provide ways to support local solar production while prioritizing access to the benefits of solar for low-income members.

Except from 2022 Budget on Increasing support for renewable energy programs.

- Low-Income Access to Solar Benefits
  - OPALCO will establish a new conduit for voluntary member donations in support of local solar energy production through community solar projects. The long-term goal is to provide a voluntary funding mechanism to enable the Energy Assistance Program (EAP) program to become fully sustainable through community solar investments dedicated to the low-income program.
  - Members will be able to opt-in to add their support as a line-item on the bill in blocks of local renewable power at $10 each.
  - All member contributions will direct OPALCO-owned community solar production credits into the Energy Assist program to assist low-income members and provide access to the benefits of solar.
  - OPALCO will continue to pursue grant funding to provide access to the benefits of solar for low-income members.
- Rooftop Solar
  - Pending RUS and Board approval, OPALCO will offer on-bill financing for solar installations and energy (battery) storage projects through the Switch it Up! Program. Terms and financing amount per meter to be determined.
  - OPALCO will offer a member workshop on rooftop solar as part of the Island Way campaign activities in 2022.
- Commercial Solar
  - OPALCO will work with Sustainable Connections to provide incentives, technical assistance and access to federal grants for commercial solar projects.
  - OPALCO will pursue grant funding to offer solar workshops tailored to business/commercial members.

Current Proposal:

Net Metering Proposed Changes: Similar to our energy efficiency rebate and low-income support programs, OPALCO is proposing to purposely increase support for renewable generation through independent and transparent programs (above) and not through unique rate structures. One of our core rate mandates is to formulate our rate structures based on the true “cost of service.” In addition to increased solar programing as outlined in the 2022 Budget, Staff is proposing the following rate structure adjustments:

Member generator impacts:

- Members' own use still offsets the grid energy and is valued at full retail rate.
- Excess generation rate adjusted to slightly less than retail rate (~$0.085/kWh vs ~0.109/kWh)*
- Annual excess generation rate adjusted to more than existing rate (~$0.085/kWh vs ~0.052/kWh)* and credited in the month produced.
- For monthly generation in excess of consumption, "banking" changes from kWh to dollar credits each month.

*Figures are rounded and reviewed during the annual budgetary process.

<u>Recommendation:</u>
Staff recommends the Board approve the proposed renewable generation tariff structures and policy found below.

> Note: These tariffs are based on the current revenue and tariff profiles. If the Board approves the budget, these tariffs will increase based on the same methodology as found in the recommended tariffs detailed in the 2022 Tariff Revision section of this Board report.

Solar Rates Proposal – Member Feedback

OPALCO announced the solar rates discussion in May of 2021 (see board materials for solar rates presentation: https://www.opalco.com/wp-content/uploads/2021/05/Solar-Member-Generation-Presentation.pdf) and has been collecting member feedback on the issue ever since. The first of two Solar Town Hall events was held on May 5th with 75 members in attendance (via Zoom) and the second Solar Town Hall – focused on the solar rate proposal that was presented to the Board in September – was held on September 20th with 115 members in attendance (via Zoom). In addition, members were notified about the solar rates discussion in the email newsletters, ads in local papers and on social media.

Staff met with members and special interest groups who reached out to us in September and October to discuss the proposal and answer questions. At the October board meeting, 18 members attended to comment on the proposal, primarily solar producers raising concerns about how the rate structure would affect solar adoption in the islands. Upon request by members, OPALCO scheduled an Energy Roundtable (via Zoom) to hear more from members on the proposal before proceeding.

In advance of the Energy Roundtable, OPALCO sent out a special email newsletter to the membership with an explanation of the problem and proposed solution with links to the full board materials and Quick Fact digest of the information. There were also articles posted in local online news blogs: Orcasonian, sanjuanislander.com and Lopez Rocks. In response to this outreach, OPALCO received about 47 written comments from members, which are included in the Appendix. Of those comments, 22 were in support of the solar rate proposal, 16 were in opposition to the proposal and 9 did not take a stance on the proposal.

The Energy Roundtable was held on November 2nd via Zoom and about 60 members attended, plus OPALCO staff and all of the OPALCO Board Members. The roundtable was moderated by Ryan Palmateer (formerly of the San Juan Islands Conservation District) who has moderated that forum for years (before COVID restricted meetings). The virtual meeting was structured to give all members in attendance an opportunity to share their ideas and opinions. The members in attendance were primarily solar producers/investors (77%). As a snapshot of the mood in the meeting: polls taken during the Energy Roundtable showed 72% support a continued subsidy for local renewable energy producers and 12% do not support a continued subsidy; 71% felt the rate paid to solar producers was just right or should be increased and 29% felt the rate should be decreased or removed. See full poll results in Appendix.

After an initial round of brief opening statements, discussion began on three topics that showed the most interest in an opening poll: 1) Prioritizing Local Energy Resilience, 2) Removing Barriers to Rooftop Solar, and 3) Affordability. See the Appendix for detailed and verbatim transcription of member comments and a recording of the meeting is available at: https://youtu.be/tk_FIXVLZZs.

The following are the main themes that we heard at the Roundtable:

Member	**Local energy resilience is one of the most important issues** today and many members want OPALCO to continue to support local as much local power as is possible.
OPALCO	We agree and our energy plan (IRP) depends on it. How we support local energy resilience is also important. The Washington Clean Energy Transformation Act (CETA) requires that while utilities transition to a carbon free future, that no members are left behind. The current proposal is designed to slowly shift solar rates to protect affordability for the whole membership between now and 2028 when, with a new power contract in place, price signals and cost parity between mainland power and solar will likely correct this issue.
Member	**Please slow down and be very thoughtful and careful with any new rate structure**. Let's ensure it is sending the right signals and supporting investment in solar installations.
OPALCO	We hear you and understand that rate structure changes are difficult. We are looking for ways to support investments in solar installations that will continue to promote growth in our local energy supply while protecting affordability for all co-op members. Keep in mind that solar members benefit from a number of co-op, state, and Federal incentives and subsidies that are subject to change: federal renewable tax credit used to be 30%, ramps down to 22% in 2023 and expires in 2024. The tax credit benefits those who needed write-offs but is of little use to low-income members. The WA Renewable Energy System Incentive Program stopped offering the incentive to new solar customers in June 2021. As emerging technologies like solar, wind and batteries mature, their subsidies ramp down. OPALCO has several new programs and incentives in the works aimed at low interest financing for solar and storage, which will help expand local renewable energy options for more people.

Member	**OPALCO should offer low-interest loans or grants** to help remove barriers for members to install solar on their homes.
OPALCO	We have applied for additional USDA funds (RESP) to add solar and battery storage projects to our on-bill financing program, Switch it Up. We expect that members will have access to those measures as soon as 2022 – and that will remove the significant barrier of upfront capital.
Member	**Concerned that the new solar rate will impact low-income members' ability to get and benefit from solar**.
OPALCO	OPALCO members from low-income households benefit from solar directly as 10% of production from the Decatur Microgrid is distributed to the Energy Assist (monthly bill credit) program; and with the upcoming Bailer Hill Microgrid, 45% of the project will go to Energy Assist. Both of these programs are funded by grants awarded to OPALCO. In addition, members can invest in Community Solar beginning at about $150 to access benefits and bill credits. Any member investing in Community Solar may dedicate all or some of their production credits to Energy Assist.
Member	**Please don't divide the membership between those who have solar and those who don't.**
OPALCO	Agreed. Cooperatives are non-profit organizations that live by the Rochdale Principles including 'democratic member control' and 'members' economic participation' and operate at the cost-of-service: each member pays their fair share of the costs to deliver power. The current proposal starts to improve the balance to prevent a significant divide in the coming years. The rate of total solar production on OPALCO's grid is growing at about 30% per year.
Member	**There are other ways OPALCO can manage its revenue.**
OPALCO	We've heard suggestions from members about eliminating credit card payments, labor costs and adjusting the service access charge up to cover fixed costs. All of these are issues are discussed during budgeting each year with consideration for the full membership. The service access charge has been shifting upwards to cover a higher percentage of fixed costs but the rate shock of covering the true cost ($118/mo in 2020) has many negative impacts (part-time, lower kWh users). OPALCO will continue to balance ALL of the rate structure components until new price signals take over.
Member	**OPALCO should not pay more for local power than it does for wholesale mainland power**.

OPALCO	OPALCO recognizes the value that local energy producers bring to the grid and wants to continue to incentivize solar – at least until the cost of solar is on par or less than the cost of mainland power (estimated in 2028). The proposed tariff includes a renewable premium – a credit – that recognizes the avoided cost for transmission (when solar producers use their own power) and a value for their contribution to our local energy supply. The proposal brings the rate down from retail (~11 cents) to ~8.5 cents for new solar producers in 2022.
Member OPALCO	**We need to flip the paradigm**. We should be encouraging conservation. Our CO-OP's income should not be based on how much energy we use. We agree that this issue must be remedied. If we could let the kWh usage (energy) be billed as a pass through, the full cost of service would be collected through a service access charge, additional demand charges and/or grid charges. There are significant trade-offs in that model, too, and the Board is cautious to avoid rate shock for the membership. The paradigm is going to flip on its own at the point that the cost of solar is level or less than wholesale power and, as the region decarbonizes, new price signals based on time of day and time of generation; the timeline is somewhere around 2030 in alignment with CETA mandates and a new contract period for OPALCO's generation purchases.

What's next for member involvement? OPALCO will continue to listen to member feedback, opinions and ideas about solar rates and will support a monthly Energy Roundtable (via Zoom as long as number of participants and/or COVID safety warrants it). The Board materials will include regular updates on the ongoing rate structure discussion – not just the solar rates, but how all rates will evolve towards the new paradigm that's coming.

Members can stay engaged by reading the monthly co-op newsletter, reviewing board materials posted online each month and attending board meetings. Staff are available to meet with members or member groups to discuss rates or other OPALCO topics. Contact us at communications@opalco.com to set up a time to meet, ask questions or share your feedback.

Please see APPENDIX for the following:

1. Digest of Member Comments
2. Verbatim Member Comments
3. Correspondence with Members
4. Transcript of Energy Roundtable and Chat
5. Energy Roundtable Poll Results
6. Orcasonian article and comments

ORCAS POWER AND LIGHT COOPERATIVE

MEMBER SERVICE POLICY 13

Interconnection of Member-owned Distributed Energy Resource Facilities

This policy covers interconnection of any member owned generating facilities, storage facilities, or other facilities supplying energy to the distribution system of the Orcas Power and Light Cooperative (OPALCO) system, herein referred to as distributed energy resource (DER). This interconnection policy for DER facilities specifies the minimum requirements and conditions for non-utility-owned electric resources that will be interconnected for the purpose of parallel operation with the OPALCO electrical system. DER facilities will be permitted to interconnect to OPALCO's distribution system only after OPALCO determines that the operation of the member's DER facility will be safe and effective and will not interfere with normal operation of OPALCO's electrical systems.

13.1 AVAILABILITY

Available to qualifying facilities subject to the limitations below:

13.1.1 Service must be supplying energy to the cooperative's distribution system with solar, wind, battery storage or other distributed energy resources.

13.1.2 Qualifying facilities must adhere to any of OPALCO's power purchasing contract provisions for interconnection of generation or other qualifying facilities.

13.2 CHARACTER OF SERVICE

Service where the member has elected to interconnect DER facilities with OPALCO's distribution facilities. The DER facilities may be used to offset the member's own electrical requirements or to supply power to sell to OPALCO. Single phase 120/240 or three phase 277/480 or 120/208 service, at 60 Hz are available. Any service upgrades necessary must comply with MS Policy 5 – *Line Extension*.

13.3 PAYMENT FOR SUPPLIED ENERGY

13.3.1 Members interconnecting DER facilities with an inverter nameplate rating of less than 25 kW shall be under the appropriate tariff.

13.3.2 Members interconnecting DER facilities with an inverter nameplate rating of 25 kW or greater shall execute a Power Purchase Agreement with the cooperative prior to operation of the system.

13.4 GENERAL PROVISIONS

13.4.1 Design Requirements

13.4.1.1 All equipment used to interconnect to the cooperative's system shall be UL listed for the intended use.

13.4.1.2 All interconnected systems shall comply with current state, national codes, and OPALCO's interconnection guidelines.

13.4.1.3 DER facilities shall have the ability to be monitored by the cooperative via communications protocols defined in the cooperative's interconnection guideline.

13.4.2 Interruption or Reduction of Deliveries

13.4.2.1 OPALCO shall not be obligated to accept deliveries of excess energy and may require member to interrupt or reduce such deliveries:

13.4.2.1.1 When necessary, to construct, install, maintain, repair, replace, remove, investigate, or inspect any of its equipment or part of its system; or

13.4.2.1.2 If it is determined that curtailment, interruption, or reduction is necessary because of emergencies, forced outages, or compliance with prudent electrical practices.

13.4.2.2 Whenever possible, OPALCO shall give the member reasonable notice of the possibility that interruption or reduction of deliveries may be required.

13.4.2.3 Notwithstanding any other provision of this policy, if, at any time OPALCO determines that either (1) the facility may endanger any of OPALCO's personnel or (2) the continued operation of member's facility may endanger the integrity of OPALCO's electric system, OPALCO shall have the right to disconnect member's generation facility from the OPALCO's electric system. The member's facility shall remain disconnected until such time as OPALCO is satisfied that the condition which necessitated the disconnection has been corrected.

13.4.3 Interconnection

13.4.3.1 OPALCO reserves the right require interconnection studies, additional or upgraded facilities, and the interconnection method. Technical provisions for interconnection shall be provide via the cooperative's interconnection guidelines.

13.4.3.2 Member shall pay for designing, installing, operating, ~~and~~ maintaining and any other associated costs of the DER facility and system upgrades, per Member Service Policy 5 – *Line Extensions,* and shall be in accordance with all applicable laws, ~~and~~ regulations, and cooperative guidelines and policies.

Member shall not commence parallel operation of the DER facility until written approval of the interconnection facilities has been given by OPALCO.

13.4.4 Maintenance and Permits

13.4.4.1 Member shall maintain the DER facility and interconnection facilities in a safe and prudent manner and in conformance with all applicable laws and regulations.

13.4.4.2 Member shall obtain any governmental authorizations and permits required for the construction and operation of the DER facility and interconnection facilities. Member shall reimburse OPALCO for all losses, damages, claims, penalties, or liability it incurs because of member's failure to obtain or maintain any governmental authorizations and permits required for construction and operation of member's DER facility or failure to properly maintain member's facility.

13.4.4.3 Member shall obtain appropriate insurance coverage before operation and provide evidence to OPALCO of such insurance, including liability coverage.

13.4.6 Indemnity and Liability

Member shall save harmless, release, and indemnify OPALCO, its officers, directors, employees, other members, and its agents, from any loss, claim or expenses, including but not limited to damages, fines, and other payments arising out of member's actions or inaction in the development and operation, or failures thereof, of its DER facilities and implementing this policy.

13.5 Member Owned Renewable Energy (MORE) Fund/Production Incentives

All MORE incentives will be funded through voluntary contributions; OPALCO offers no guaranteed incentive payments. New DERs will be admitted into the MORE Incentive Program on a first come, first served basis after July 1, 2010. MORE installations will follow the Net Metering Section 14.4 of this policy.

13.5.1 Production meter: Member will install, at their expense, a meter base which will accommodate an OPALCO meter. The production meter is a separate meter from the OPALCO billing meter and is required to record all energy produced from the DER.

13.5.2 Incentives will be administered through an independent committee of OPALCO members following approved MORE committee guidelines. See MORE guidelines for more details.

ORCAS POWER AND LIGHT COOPERATIVE

TARIFF RDR – 21

RESIDENTIAL DISTRIBUTED ENERGY RESOURCE SERVICE

FIRST REVISION

AVAILABILITY

Available to all residential members utilizing Member Service Policy 13 for interconnection of distributed energy resource (DER) facilities, subject to the General Provisions hereunder. DER facilities include solar, wind, hydro, and battery storage.

TYPE OF SERVICE

Single-phase, at available secondary voltage, equipment subject to automatic load management controls.

APPLICATION

- Primary residential interconnected DER facilities end-use shall be served under this tariff.
- Services with interconnected DER facilities with an inverter nameplate rating of less than 25 kW. [Systems above 25kW will require an independent power purchase agreement]

SERVICE ACCESS CHARGE $48.41 per billing period

ENERGY ASSISTANCE CHARGE (See General Provision #6) $0.00076 per kWh

NET CONSUMED ENERGY (Wholesale + Grid)

Wholesale Purchased Power			$0.0470 per kWh
Grid Usage	Summer	Winter	
Block 1	≤ 2,000 kWh	≤4,000 kWh	$0.0619 per kWh
Block 2	2,001 - 3,000 kWh	4,001 - 5,000 kWh	$0.0764 per kWh
Block 3	> 3,000 kWh	>5,000 kWh	$0.0994 per kWh

NET PRODUCED ENERGY

Renewable Generation Credit	-$0.0952 per kWh
Grid Usage Charge	$0.0103 per kWh

DEMAND CHARGE $0.0000 per kW

MINIMUM MONTHLY CHARGE

The minimum monthly charge, under the above rate, shall be the above Service Access Charge per billing period or prorated if service is provided for less than a full billing period.

POWER COST ADJUSTMENT

A surcharge or credit may be applied to each billing for service under this tariff to reflect increases or decreases in the cost of power subject to OPALCO Policy 29 – *Rate Design* and Tariff ECA. (See General Provision #6)

GENERAL PROVISIONS

1. Member agrees to allow the cooperative, at its discretion, to install automatic load management controls.
2. Primary end-use for residential purposes utilizing Member Service Policy 13 shall be served under this tariff.
3. Summer Block shall be defined as May billing period through September billing period; Winter Block shall be defined as October billing period through April billing period.
4. Net Consumed Energy shall be charges applied to all energy (kWh) consumed at the time where consumption exceeds production. This energy shall be measured at the interconnection meter.
5. Net Produced Energy shall be credits and charges applied to all energy (kWh) produced at the time where production exceeds consumption. This energy shall be measured at the interconnection meter. The sum of all credits and charges totals to a credit.
6. Energy Assistance Charge and Energy Charge Adjustment shall be applied to all energy (kWh) Consumed Energy in the billing period.
7. Services installed, commissioned, and energized prior to March 31st, 2022, may remain on the legacy tariff method used for the March 2022 billing period for interconnected DER facilities provided the cooperative has been notified on or prior to March 31st, 2022.
8. Services billed on a legacy tariff method shall continue using that prior tariff method until one of the following conditions has been met:
   - the service is transferred to another member;
   - an executed agreement to be bound by this tariff;
   - an executed agreement requiring participation in this tariff; or
   - after June 30th, 2029.
9. Wholesale Purchased Power (charge or credit) is the annual blended per kWh charge for OPALCO's cost of wholesale power from the mainland suppliers.
10. Renewable Premium includes costs for reduced load on the grid, an environmental credit, and an implementation phase-in credit.
11. Services utilizing this tariff shall not revert to legacy tariff methodology

ORCAS POWER AND LIGHT COOPERATIVE

TARIFF CDR – 21

COMMERCIAL DISTRIBUTION ENERGY RESOURCE SERVICE
FIRST REVISION

AVAILABILITY

Available to all non-residential members utilizing Member Service Policy 13 for interconnection of distributed energy resource (DER) facilities and metered at more than 20 kW in any one or more of the preceding twelve (12) months, subject to the General Provisions hereunder. DER facilities include solar, wind, hydro, and battery storage.

TYPE OF SERVICE

Single-phase or three-phase, at available secondary voltage, equipment subject to automatic load management controls.

APPLICATION

- Primary commercial interconnected DER facilities end-use shall be served under this tariff.
- Services with interconnected DER facilities with an inverter nameplate rating of less than 25 kW. [Systems above 25kW will require an independent power purchase agreement]

SERVICE ACCESS CHARGE		$67.57 per billing period
ENERGY ASSISTANCE CHARGE		$0.00076 per kWh (See General Provision #6)
NET CONSUMED ENERGY (Wholesale + Grid Usage)		
Wholesale Purchased Power		$0.0470 per kWh
Grid Usage		
Block 1	≤ 5,000 kWh	$0.0505 per kWh
Block 2	5,001 - 150,000 kWh	$0.0611 per kWh
Block 3	> 150,000 kWh	$0.0971 per kWh
NET PRODUCED ENERGY		
Renewable Generation Credit		-$0.0952 per kWh
Grid Usage Charge		$0.0103 per kWh
DEMAND CHARGE		
Demand Block 1 (≤300 kW)		$3.94 per kW
Demand Block 2 (>300 kW)		$5.92 per kW

MINIMUM MONTHLY CHARGE

The minimum monthly charge, under the above rate, shall be the above Service Access Charge per billing period or prorated if service is provided for less than a full billing period.

DETERMINATION OF BILLING DEMAND

The billing demand shall be the maximum kilowatt (kW) demand established by the member for any period of fifteen (15) consecutive minutes during the period for which the bill is rendered as indicated or recorded by a demand meter.

POWER COST ADJUSTMENT

A surcharge or credit may be applied to each billing for service under this tariff to reflect increases or decreases in the cost of power, subject to Member Services Policy 29 – *Rate Design* and Tariff ECA. (See General Provision #6)

GENERAL PROVISIONS

1. Member agrees to allow the cooperative, at its discretion, to install automatic load management controls.
2. Primary end-use for commercial purposes shall be served by this tariff.
3. Net Consumed Energy shall be charges applied to all energy (kWh) consumed at the time where consumption exceeds production. This energy shall be measured at the interconnection meter.
4. Net Produced Energy shall be credits and charges applied to all energy (kWh) produced at the time where production exceeds consumption. This energy shall be measured at the interconnection meter. The sum of all credits and charges totals to a credit.
5. Energy Assistance Charge and Energy Charge Adjustment shall be applied to all energy (kWh) Consumed Energy in the billing period.
6. Services installed, commissioned, and energized prior to March 31st, 2022, may remain on the legacy tariff method used for the March 2022 billing period for interconnected DER facilities provided the cooperative has been notified on or prior to March 31st, 2022.
7. Services billed on a legacy tariff method shall continue using that prior tariff method until one of the following conditions has been met:
   - the service is transferred to another member;
   - an executed agreement to be bound by this tariff;
   - an executed agreement requiring participation in this tariff; or
   - after June 30th, 2029.
8. Wholesale Purchased Power (charge or credit) is the annual blended per kWh charge for OPALCO's cost of wholesale power from the mainland suppliers.
9. Renewable Premium includes costs for reduced load on the grid, an environmental credit, and an implementation phase-in credit.
10. Services utilizing this tariff shall not revert to legacy tariff methodology.

Budget 2022

Attached please find our 2022 Budget Presentation. Consistent with last year's projections, staff is recommending a 4% rate increase for the 2022 budget year and forecasting between 4%-6% over the following four years. Staff is recommending that our 2022 budget revenue increase from $32.7M (projected 2021) to $34.3M to meet our financial, operational and capital project commitments. The projected figures for years 2023 thru 2026 are for reference only, as future years will be reviewed annually during our normal budgeting process.

OPALCO is strategically positioned to address the future power needs of our membership and sustain our island communities through the escalating costs and challenges of the carbon-free economy. With Washington's Clean Energy Transformation Act (CETA), the clock is now ticking. OPALCO has the expertise in its Board, management and team to get the job done; and, thanks to the foresight of recent past boards, we have built the modern grid and communication infrastructure required to succeed. In 2021, OPALCO was awarded multiple grants from the Department of Commerce's Clean Energy Fund to begin designing projects that will become the foundation for local energy resilience and help usher in the new paradigm of electric transportation, renewable generation and a more transactive member experience with their power usage and production. The Island Way Campaign launched, telling the story of OPALCO's vision, bringing members into their part of the story and increasing participation in programs such as Switch it Up – on bill finance for efficiency measures.

There are very few discretionary expenses and are constantly exploring ways to reduce costs to our membership. The Co-op budget is tightly constrained: one-third for power costs; one-third for labor (bargaining unit and competitive wage rates) and most of the final third in fixed costs such as plant, mortgage and operations; discretionary expenses are largely limited to member facing programs. After a year of austerity budgeting due to COVID including no retail rate increases for the membership in 2021, the 2022 budget starts to add member programs back in including the potential of an in-person annual meeting, the return of the youth scholarship program and more member meetings to continue building on the Island Way Campaign.

With the high cost of living in the islands and recent escalation of inflation, OPALCO is adding new resources to bill paying assistance for member households of low and fixed income through the Bailer Hill Microgrid Project. A $1M grant through the Department of Commerce dedicates up to 45% of the production credits from that project to be channeled into Energy Assist, which will help raise the monthly bill credit to offset the rate increase. Project PAL continues to be administered through the three island family resource centers.

The 2022 budget continues to align our operations to the mission statement of providing safe, reliable, cost effective, and environmentally sensitive utility services. This budget prepares OPALCO to meet the marks set out in our energy road map:

> TODAY: Make the most of our available resources. Reduce members' total energy bills through electrification of transportation and heating while continuing to modernize the grid to meet future needs. Leverage grants, state and federal programs to help members increase efficiency and position themselves for sustainability in the coming carbon economy.

TOMORROW: Increase local resilience. Bring more local renewables on, leveraging our dynamic grid and building emergency back-up power for emergency services. Prepare for grid parity when renewables (local and regional) will be less expensive than our mainland power provider.

FUTURE: Give members more control. In the coming "transactive" energy world, members will dynamically buy and sell local power, make decisions about their power usage in response to real time price signals and integrate energy storage (EVs, batteries…) into the Co-op grid. To give members access to this dynamic power world, OPALCO must begin to upgrade transformers and other equipment to provide the capacity necessary to manage the number of EVs, local distributed power generators and battery storage units that will be commonplace in member homes – as well as smart appliances and individual devices.

The 2022 budget includes the Bailer Hill Microgrid Project (on San Juan Island): OPALCO's second community solar project with energy storage. The Friday Harbor substation will be updated with a new transformer for greater capacity and to replace aging equipment. Operations will replace 15 miles of URD as well as routine replacement of distribution and transmission poles.

We curtailed expense in 2021 due to COVID impacts knowing the challenging it would present in future years. The rate increases forecast for the next four years must reposition the Co-op's equity for capital projects on the horizon including a major submarine cable replacement from Lopez to Orcas in 2030. The 2020 and 2021 budgets included $200k for COVID assistance; the 2022 includes $50k as pandemic recovery in San Juan County begins to wind down.

Staff recommends Board make a motion to approve the 2021 budget as submitted.

Attached please find our 2022 Budget Presentation.

Subsidiary Action (Rock Island Communications)

CoBank Loan Guarantee Increase

On November 29, 2021, the OPALCO Board of Directors will have a work session to review Rock Island business, including a discussion about increasing to the OPALCO Loan Guarantee with CoBank by $2M.

The purpose of the increase would be to continue connection incentives for new fiber builds and to meet the budgetary challenges that supply chain issues, inflation and labor continue to present.

Please note that as Rock Island is a wholly owned subsidiary with separate finances, this decision would not affect OPALCO rates or translate to any financial impact on OPALCO members.

Staff will make any recommendations coming out this work session during the regular business of the November 30, 2021 meeting of the Board.

DISCUSSION ITEMS

2022 Tariff Revisions (First Read)

The Board will review a comprehensive set of tariff options. The tariffs below have been edited to include the recommended revenue increases to meet the revenue requirements as proposed in the 2022 budget. The first set of tables show the current tariffs, proposed tariffs, and other tariff options. Also included is the comprehensive tariff document which is based on the proposed tariff.

This is the first read, and if approved after the second read, staff will implement the tariffs in the January 2022 billing period.

A.			B.	C.	D.	E.
Residential			Present Rates	**Recommended Even 4% increase to all components**	All Facility/Demand	All Energy
Service Access Charge ($/Service/Month)			$48.41	**$50.35**	$54.60	$48.41
Energy Assistance Program ($/kWh)			$0.00076	**$0.00079**	$0.00079	$0.00079
Energy Rates ($/kWh)						
	Summer	Winter				
Block 1	< 2,000 kWh	< 4,000 kWh	$0.1089	**$0.1133**	$0.1089	$0.1152
Block 2	2,000 kWh to 3000 kWh	4,000 kWh to 5,000 kWh	$0.1234	**$0.1284**	$0.1234	$0.1305
Block 3	> 3,000 kWh	> 5,000 kWh	$0.1421	**$0.1478**	$0.1421	$0.1502

Residential Distributed Energy Resource			Present Rates	**Recommended Even 4% increase to all components**	All Facility/Demand	All Energy
Service Access Charge ($/Service/Month)			$48.41	**$50.35**	$54.60	$48.41
Energy Assistance Program ($/kWh)			$0.00076	**$0.00079**	$0.00079	$0.00079
Net Consumed Energy Rates ($/kWh)						
	Summer	Winter				
Block 1	< 2,000 kWh	< 4,000 kWh	$0.1089	**$0.1133**	$0.1089	$0.1152
Block 2	2,000 kWh to 3000 kWh	4,000 kWh to 5,000 kWh	$0.1234	**$0.1284**	$0.1234	$0.1305
Block 3	> 3,000 kWh	> 5,000 kWh	$0.1421	**$0.1478**	$0.1421	$0.1502
Net Produced Energy ($/kWh)						
Renewable Generation Credit			($0.0952)	**($0.0990)**	($0.0952)	($0.0990)
Grid Usage Charge			$0.0103	**$0.0108**	$0.0103	$0.0108

Residential TOU	Present Rates	**Recommended Even 4% increase to all components**	All Facility/Demand	All Energy
Service Access Charge ($/Service/Month)	$58.20	**$60.53**	$69.00	$58.20
Energy Assistance Program ($/kWh)	$0.00076	**$0.00079**	$0.00079	$0.00079
Energy Rates ($/kWh)				
TOU Period 1 (6 AM - Noon)	$0.1805	**$0.1878**	$0.1805	$0.1905
TOU Period 2 (Noon - 6 PM)	$0.1083	**$0.1127**	$0.1083	$0.1143
TOU Period 3 (6 PM - 8 PM)	$0.1805	**$0.1878**	$0.1805	$0.1905
TOU Period 3 (8 PM - 6 AM)	$0.0490	**$0.0510**	$0.0490	$0.0518

Small Commercial (<20 kW)	Present Rates	Recommended Even 4% increase to all components	All Facility/Demand	All Energy
Service Access Charge ($/Service/Month)	$67.57	**$70.28**	$74.50	$67.57
Energy Assistance Program ($/kWh)	$0.00076	**$0.00079**	$0.00079	$0.00079
Energy Rates ($/kWh)				
Block 1 (< 5,000 kWh)	$0.1074	**$0.1117**	$0.1074	$0.1187
Block 2 (> 5,000 kWh)	$0.1190	**$0.1238**	$0.1199	$0.1324
Demand Rates ($/kW)				
First 20 kW (Flat Rate)	$6.41	**$6.67**	$6.94	$6.41

Large Commercial (> 20kW)	Present Rates	Recommended Even 4% increase to all components	All Facility/Demand	All/Energy/Demand
Service Access Charge ($/Service/Month)	$67.57	**$70.28**	$82.75	$67.57
Energy Assistance Program ($/kWh)	$0.00076	**$0.00079**	$0.00079	$0.00079
Energy Rates ($/kWh)				
Block 1 (< 5,000 kWh)	$0.0975	**$0.1014**	$0.0975	$0.1017
Block 2 (5,000-150,000 kWh)	$0.1081	**$0.1125**	$0.1081	$0.1128
Block 3 (>150,000 kWh)	$0.1441	**$0.1499**	$0.1441	$0.1503
Demand Rates ($/kW)				
Block 1 (< 300 kW)	$3.94	**$4.10**	$4.83	$4.11
Block 2 (> 300 kW)	$5.92	**$6.16**	$7.26	$6.17

Commercial Distributed Energy Resource	Present Rates	Recommended Even 4% increase to all components	0.00079	All/Energy/Demand
Service Access Charge ($/Service/Month)	$67.57	**$70.28**	$82.75	$67.57
Energy Assistance Program ($/kWh)	$0.00076	**$0.00079**	$0.00079	$0.00079
Energy Rates ($/kWh)				
Block 1 (< 5,000 kWh)	$0.0975	**$0.1014**	$0.0975	$0.1017
Block 2 (5,000-150,000 kWh)	$0.1081	**$0.1125**	$0.1081	$0.1128
Block 3 (>150,000 kWh)	$0.1441	**$0.1499**	$0.1441	$0.1503
Net Produced Energy Rates ($/kWh)				
Renewable Generation Credit	($0.0952)	**($0.0990)**	($0.0952)	($0.0990)
Grid Usage Charge	$0.0103	**$0.0108**	$0.0103	$0.0108
Demand Rates ($/kW)				
Block 1 (< 300 kW)	$3.94	**$4.10**	$4.83	$4.11
Block 2 (> 300 kW)	$5.92	**$6.16**	$7.26	$6.17

A.	B.	C.	D.	E.
Pumps	Present Rates	**Recommended Even 4% increase to all components**	All Facility/Demand	All Energy
Service Access Charge ($/Service/Month)	$43.49	**$45.23**	$47.95	$42.28
Energy Assistance Program ($/kWh)	$0.00076	**$0.00079**	$0.00079	$0.00079
Energy Rates ($/kWh)				
0 - 370 kWh	$0.1157	**$0.1204**	$0.1157	$0.1294
370-5,000 kwh	$0.0927	**$0.0965**	$0.0927	$0.1037
Over 5,000 kWh	$0.1126	**$0.1172**	$0.1126	$0.1259
Demand Rates ($/kW)				
First 20 kW (Flat Rate)	$1.21	**$1.26**	$1.34	$1.21
Over 20 kW	$3.99	**$4.15**	$4.40	$3.99

Energy Assist	Present Rates	**Recommended Even 4% increase to all components**
Energy Assistance Program ($/kWh)	$0.00076	**$0.00079**
Household Size ($ Credit/Month)		
1	($31.41)	**($32.67)**
2	($37.41)	**($38.91)**
3	($43.41)	**($45.15)**
4	($49.41)	**($51.39)**
5	($55.41)	**($57.63)**
6+	($61.41)	**($63.87)**

Private Outdoor Lighting	Present Rates	**Recommended Even 4% increase to all components**
Billing Charge ($/Service/Month)	$2.79	**$2.91**
Fixture Charge ($/Service/Month)	$12.61	**$13.12**
Energy Rates ($/kWh)		
100 Watt Light (and LED Equivalent)	$4.64	**$4.8256**
200 Watt Light (and LED Equivalent)	$9.42	**$9.80**

Line Retention	Present Rates	**Recommended Even 4% increase to all components**
Service Access Charge ($/Service/Month)	$43.49	**$45.23**

	A.	B.	C.
105–106	**Deposits and Charges**	Present Rates	**Recommended**
107	New Members		
108	Membership Fee	$5.00	**$5.00**
109	Deposits (Refundable):		
110	Residential/Residential TOU	$200.00	**$250.00**
111	Commercial (Small/Large)	TBD by OPALCO*	**TBD by OPALCO***
112	*Surety bond required in amount of deposit		
113	New of Transfer Service	$20.00	**$25.00**
114	~~Non-sufficient Funds (NSF) Check~~ Returned Payment Charge	$25.00	**$30.00**
115	Late Payment Charge	5% of current charges	**5% of current charges**
116	Disconnect/Reconnect Fees		
117	Disconnect Notice	$5.00	**$10.00**
118	Door Tag Fee		**$50.00**
119	Reconnect (After Disconnt for Non-payment)		
120	Prior to Disconnection of meter	$25.00	**Merge with After**
121	After Disconnection of meter		**Merge with Prior**
122	During OPALCO business hours	$50.00	**$75.00**
123	Outside of OPALCO business hours	$100.00	**$150.00**
124	Seasonal Reconnect (after disconnected for two (2) or more consecutive billing periods)		
125	During OPALCO business hours	$200.00	**$200.00**
126	Outside of OPALCO business hours	$350.00	**$350.00**
127	Member Caused Outage	Actual Cost	**Actual Cost**
128	Meter Seal Breakage	$75.00	**$100.00**
129	Meter Test Fee (at member's request)		
130	Performed by OPALCO	$50.00	**$100.00**
131	Performed by other qualified person	Actual Cost**	**Actual Cost****
132	**OPALCO will refund cost of meter testing if proven in error by more than two percent (2%)		

Summary of Tariffs

Residential			Charge (Credit)
Service Access Charge ($/Service/Month)			$50.35
Energy Assistance Program ($/kWh)			$0.00079
Energy Rates ($/kWh)			
	Summer	Winter	
Block 1	< 2,000 kWh	< 4,000 kWh	$0.1133
Block 2	2,000 kWh to 3000 kWh	4,000 kWh to 5,000 kWh	$0.1284
Block 3	> 3,000 kWh	> 5,000 kWh	$0.1478

Residential TOU	$0.00
Service Access Charge ($/Service/Month)	$60.53
Energy Assistance Program ($/kWh)	$0.00079
Energy Rates ($/kWh)	
TOU Period 1 (6 AM - Noon)	$0.1878
TOU Period 2 (Noon - 6 PM)	$0.1127
TOU Period 3 (6 PM - 8 PM)	$0.1878
TOU Period 3 (8 PM - 6 AM)	$0.0510

Small Commercial (<20 kW)	$0.00
Service Access Charge ($/Service/Month)	$70.28
Energy Assistance Program ($/kWh)	$0.00079
Energy Rates ($/kWh)	
Block 1 (< 5,000 kWh)	$0.1117
Block 2 (> 5,000 kWh)	$0.1238
Demand Rates ($/kW)	
First 20 kW (Flat Rate)	$6.67

Large Commercial (> 20kW)	0
Service Access Charge ($/Service/Month)	$70.28
Energy Assistance Program ($/kWh)	$0.00079
Energy Rates ($/kWh)	
Block 1 (< 5,000 kWh)	$0.1014
Block 2 (5,000-150,000 kWh)	$0.1125
Block 3 (>150,000 kWh)	$0.1499
Demand Rates ($/kW)	
Block 1 (< 300 kW)	$4.10
Block 2 (> 300 kW)	$6.16

Pumps	0
Service Access Charge ($/Service/Month)	$45.23
Energy Assistance Program ($/kWh)	$0.00079
Energy Rates ($/kWh)	
0 - 370 kWh	$0.1204
370-5,000 kwh	$0.0965
Over 5,000 kWh	$0.1172
Demand Rates ($/kW)	
First 20 kW (Flat Rate)	$1.26
Over 20 kW	$4.15

Residential DER			Charge (Credit)
Service Access Charge ($/Service/Month)			$50.35
Energy Assistance Program ($/kWh)			$0.00079
Net Consumed Energy Rates ($/kWh)			
	Summer	Winter	
Block 1	< 2,000 kWh	< 4,000 kWh	$0.1133
Block 2	2,000 kWh to 3000 kWh	4,000 kWh to 5,000 kWh	$0.1284
Block 3	> 3,000 kWh	> 5,000 kWh	$0.1478
Net Producned Energy Rates ($/kWh)			
Renewable Generation Credit			($0.0990)
Grid Usage Charge			$0.0108

Energy Assist	Charge (Credit)
Energy Assistance Program ($/kWh)	$0.00079
Household Size ($ Credit/Month)	
1	($32.67)
2	($38.91)
3	($45.15)
4	($51.39)
5	($57.63)
6+	($63.87)

Private Outdoor Lighting	Charge (Credit)
Billing Charge ($/Service/Month)	$2.91
Fixture Charge ($/Service/Month)	$13.12
Energy Rates ($/kWh)	
100 Watt Light (and LED Equivalent)	$4.8256
200 Watt Light (and LED Equivalent)	$9.80

Line Retention	Charge (Credit)
Service Access Charge ($/Service/Month)	$45.23

Deposits and Charges	Charge (Credit)
New Members	
Membership Fee	$5.00
Deposits (Refundable):	
Residential/Residential TOU	$250.00
Commercial (Small/Large)	TBD by OPALCO*
*Surety bond required in amount of deposit	
New of Transfer Service	$25.00
Returned Payment Charge	$30.00
Credit Card Fee (per transaction)	$2.00
Late Payment Charge	5% of current charges
Disconnect/Reconnect Fees	
Disconnect Notice	$10.00
Door Tag Fee	$50.00
Reconnect (After Disconnt for Non-payment)	
Prior to Disconnection of meter	Merge with After
After Disconnection of meter	Merge with Prior
During OPALCO business hours	$75.00
Outside of OPALCO business hours	$150.00
Seasonal Reconnect (after disconnected for two (2) or more consecutive billing periods)	
During OPALCO business hours	$200.00
Outside of OPALCO business hours	$350.00
Member Caused Outage	Actual Cost
Meter Seal Breakage	$100.00
Meter Test Fee (at member's request)	
Performed by OPALCO	$100.00
Performed by other qualified person	Actual Cost**
**OPALCO will refund cost of meter testing if proven in error by more than two percent (2%)	

Commercial DER	Charge (Credit)
Service Access Charge ($/Service/Month)	$70.28
Energy Assistance Program ($/kWh)	$0.00079
Net Consumed Energy Rates ($/kWh)	
Block 1 (< 5,000 kWh)	$0.1014
Block 2 (5,000-150,000 kWh)	$0.1125
Block 3 (>150,000 kWh)	$0.1499
Net Consumed Energy Rates ($/kWh)	
Renewable Generation Credit	($0.0990)
Grid Usage Charge	$0.0108
Demand Rates ($/kW)	
Block 1 (< 300 kW)	$4.10
Block 2 (> 300 kW)	$6.16

Tariff R – Residential Service

Availability

Available to all small farm and home members, subject to the General Provisions hereunder.

Type of Service

Single-phase, at available secondary voltage, equipment subject to automatic load management controls.

Application

Service for home and farm uses, such as cooking, lighting, heating, private docks not used for commercial purposes, etc. Primary residential end-use shall be served under this tariff.

Charges (Credits)

Charge (Credit) Type	**Charge (Credit) Amount**			
Service Access	$50.35			$/billing period
Energy				
	Summer Thresholds	**Winter Thresholds**		
Block 1	≤ 2,000 kWh	≤ 4,000 kWh	$0.1133	$/kWh
Block 2	2,001 - 3,000 kWh	4,001 – 5,000 kWh	$0.1284	$/kWh
Block 3	> 3,000 kWh	> 5,000 kWh	$0.1478	$/kWh
Demand	$0.00			$/kW
Energy Assistance	Charges as found in EAP Tariff. See General Provision #6.			$/kWh
Energy Charge Adjustment	Charges as found in ECA Tariff. See General Provision #6.			$/kWh

General Provisions

1. The minimum monthly charge, under this tariff, shall be per the Service Access Charge, as found in Charges (Credits), per billing period or prorated if service is provided for less than a full billing period.
2. A surcharge or credit may be applied to each billing for service under this tariff to reflect increases or decreases in cost of power subject to Member Services Policy 29 – Rate Design and Tariff ECA – *Energy Charge Adjustments*.
3. Member agrees to allow the cooperative, at its discretion, to install automatic load management controls.
4. Primary end-use for residential purposes shall be served under this tariff.
5. Summer Block is defined as May billing period through September billing period; Winter Block is defined as October billing period through April billing period.
6. Energy Assistance Charge and Energy Charge Adjustment shall be applied to all energy (kWh) Consumed Energy in the billing period.

Tariff RDR – Residential Distributed Energy Resource Service

Availability

Available to all residential members utilizing Member Service Policy 13 for interconnection of distributed energy resource (DER) facilities, subject to the General Provisions hereunder. DER facilities include solar, wind, hydro, and battery storage.

Type of Service

Single-phase, at available secondary voltage, equipment subject to automatic load management controls.

Application

- Primary residential interconnected DER facilities end-use shall be served under this tariff.
- Services with interconnected DER facilities with an inverter nameplate rating of less than 25 kW. [Systems above 25kW will require an independent power purchase agreement]

Charges (Credits)

Charge (Credit) Type	**Charge (Credit) Amount**			
Service Access			$50.35	$/billing period
Net Consumed Energy				
Wholesale Purchased Power			$0.0470	$/kWh
	Summer Thresholds	**Winter Thresholds**		
Block 1	≤ 2,000 kWh	≤ 4,000 kWh	$0.0663	$/kWh
Block 2	2,001 - 3,000 kWh	4,001 – 5,000 kWh	$0.0814	$/kWh
Block 3	> 3,000 kWh	> 5,000 kWh	$0.1008	$/kWh
Net Produced Energy				
Renewable Generation Credit			$(0.0990)	$/kWh
Grid Usage Charge			$0.0108	$/kWh
Demand	$0.00			$/kW
Energy Assistance	Charges as found in EAP Tariff. See General Provision #6.			$/kWh
Energy Charge Adjustment	Charges as found in ECA Tariff. See General Provision #6.			$/kWh

General Provisions

1. The minimum monthly charge, under this tariff, shall be per the Service Access Charge, as found in Charges (Credits), per billing period or prorated if service is provided for less than a full billing period.
2. A surcharge or credit may be applied to each billing for service under this tariff to reflect increases or decreases in cost of power subject to Member Services Policy 29 – Rate Design and Tariff ECA – *Energy Charge Adjustments*.
3. Member agrees to allow the cooperative, at its discretion, to install automatic load management controls.

4. Primary end-use for residential purposes shall be served under this tariff.
5. Summer Block is defined as May billing period through September billing period; Winter Block is defined as October billing period through April billing period.
6. Energy Assistance Charge and Energy Charge Adjustment shall be applied to all energy (kWh) Consumed Energy in the billing period.
7. Net Consumed Energy shall be charges applied to all energy (kWh) consumed at the time where consumption exceeds production. This energy shall be measured at the interconnection meter.
8. Net Produced Energy shall be credits and charges applied to all energy (kWh) produced at the time where production exceeds consumption. This energy shall be measured at the interconnection meter. The sum of all credits and charges totals to a credit.
9. Services installed, commissioned, and energized prior to March 31st, 2022, may remain on the Legacy Renewable Energy Rider method for interconnected
10. Services billed on the Legacy Renewable Energy Rider shall continue using that Legacy Renewable Energy Rider until one of the following conditions has been met:
    - the service is transferred to another member;
    - an executed agreement to be bound by this tariff;
    - an executed agreement requiring participation in this tariff; or
    - after June 30th, 2029.
11. Wholesale Purchased Power (charge or credit) is the annual blended per kWh charge for OPALCO's cost of wholesale power from the mainland suppliers.
12. Renewable Premium includes costs for reduced load on the grid, an environmental credit, and an implementation phase-in credit.
13. Services utilizing this tariff shall not revert to legacy tariff methodology.

Tariff TOU – Residential Time of Use Service

Availability
Available to all small farm and home members otherwise served under the standard residential rate, and subject to the General Provisions hereunder.

Type of Service
Single-phase, at available secondary voltage, equipment subject to automatic load management controls.

Application
Service for small farms, homes, pools, greenhouses and other non-essential loads. Limited to single phase loads. Primary residential end-use shall be served under this tariff.

Charges (Credits)

Charge (Credit) Type	Charge (Credit) Amount	
Service Access	$60.53	$/billing period
Energy		
TOU Period 1	$0.1878	$/kWh
TOU Period 2	$0.1127	$/kWh
TOU Period 3	$0.1878	$/kWh
TOU Period 4	$0.0510	$/kWh
Demand	$0.00	$/kW
Energy Assistance	Charges as found in EAP Tariff. See General Provision #6.	$/kWh
Energy Charge Adjustment	Charges as found in ECA Tariff. See General Provision #6.	$/kWh

General Provisions
1. The minimum monthly charge, under this tariff, shall be per the Service Access Charge, as found in Charges (Credits), per billing period or prorated if service is provided for less than a full billing period.
2. A surcharge or credit may be applied to each billing for service under this tariff to reflect increases or decreases in cost of power subject to Member Services Policy 29 – Rate Design and Tariff ECA – *Energy Charge Adjustments*.
3. Member agrees to allow the cooperative, at its discretion, to install automatic load management controls.
4. Primary end-use for residential purposes shall be served under this tariff.
5. Summer Block is defined as May billing period through September billing period; Winter Block is defined as October billing period through April billing period.
6. Energy Assistance Charge and Energy Charge Adjustment shall be applied to all energy (kWh) Consumed Energy in the billing period.
7. Member agrees to be billed on this rate for a minimum of 12 billing periods.

Tariff SCS – Small Commercial Service

Availability

Available to all non-residential members using less than 20 kW in all of the preceding twelve (12) months, subject to the General Provisions hereunder.

Type of Service

Single-phase or three phase, at available secondary voltage, equipment subject to automatic load management controls.

Application

General Service for heating, lighting, etc., for non-residential primary end-use.

Charges (Credits)

Charge (Credit) Type	**Charge (Credit) Amount**		
Service Access		$67.57	$/billing period
Energy			
Block 1	≤ 5,000 kWh	$0.1117	$/kWh
Block 3	> 5,000 kWh	$0.1238	$/kWh
Demand	First 20 kW (Flat Rate)	$6.67	$/billing period
Energy Assistance	Charges as found in EAP Tariff. See General Provision #6.		$/kWh
Energy Charge Adjustment	Charges as found in ECA Tariff. See General Provision #6.		$/kWh

General Provisions

1. The minimum monthly charge, under this tariff, shall be per the Service Access Charge, as found in Charges (Credits), per billing period or prorated if service is provided for less than a full billing period.
2. A surcharge or credit may be applied to each billing for service under this tariff to reflect increases or decreases in cost of power subject to Member Services Policy 29 – Rate Design and Tariff ECA – *Energy Charge Adjustments*.
3. The billing demand shall be the maximum kilowatt (kW) demand established by the member for any period of fifteen (15) consecutive minutes during the period for which the bill is rendered as indicated or recorded by a demand meter.
4. Member agrees to allow the cooperative, at its discretion, to install automatic load management controls.
5. Energy Assistance Charge and Energy Charge Adjustment shall be applied to all energy (kWh) Consumed Energy in the billing period.

Tariff LCS – Large Commercial Service

Availability

Available to all non-residential members using more than 20 kW in any one or more of the preceding twelve (12) months, subject to the General Provisions hereunder.

Type of Service

Single-phase, at available secondary voltage, equipment subject to automatic load management controls.

Application

General Service for heating, lighting, etc., for non-residential primary end-use.

Charges (Credits)

Charge (Credit) Type	Charge (Credit) Amount		
Service Access		$67.57	$/billing period
Energy			
Block 1	≤ 5,000 kWh	$0.1014	$/kWh
Block 2	5,001 - 150,000 kWh	$0.1125	$/kWh
Block 3	> 150,000 kWh	$0.1499	$/kWh
Demand			
Block 1	≤ 300	$4.10	$/kW
Block 2	> 300	$6.16	$/kWh
Energy Assistance	Charges as found in EAP Tariff. See General Provision #6.		$/kWh
Energy Charge Adjustment	Charges as found in ECA Tariff. See General Provision #6.		$/kWh+

General Provisions

1. The minimum monthly charge, under this tariff, shall be per the Service Access Charge, as found in Charges (Credits), per billing period or prorated if service is provided for less than a full billing period.
2. A surcharge or credit may be applied to each billing for service under this tariff to reflect increases or decreases in cost of power subject to Member Services Policy 29 – Rate Design and Tariff ECA – *Energy Charge Adjustments*.
3. The billing demand shall be the maximum kilowatt (kW) demand established by the member for any period of fifteen (15) consecutive minutes during the period for which the bill is rendered as indicated or recorded by a demand meter.
4. Member agrees to allow the cooperative, at its discretion, to install automatic load management controls.
5. Energy Assistance Charge and Energy Charge Adjustment shall be applied to all energy (kWh) Consumed Energy in the billing period.

Tariff CDR – Commercial Distributed Energy Resource Service

Availability

Available to all non-residential members utilizing Member Service Policy 13 for interconnection of distributed energy resource (DER) facilities and metered at more than 20 kW in any one or more of the preceding twelve (12) months, subject to the General Provisions hereunder. DER facilities include solar, wind, hydro, and battery storage.

Type of Service

Single-phase or three-phase, at available secondary voltage, equipment subject to automatic load management controls.

Application

- Primary residential interconnected DER facilities end-use shall be served under this tariff.
- Services with interconnected DER facilities with an inverter nameplate rating of less than 25 kW. [Systems above 25kW will require an independent power purchase agreement]

Charges (Credits)

Charge (Credit) Type	**Charge (Credit) Amount**		
Service Access		$67.57	$/billing period
Net Consumed Energy			
Wholesale Purchased Power		$0.0470	$/kWh
	Threshold		
Block 1	≤ 5,000 kWh	$0.0544	$/kWh
Block 2	5,001 - 150,000 kWh	$0.0655	$/kWh
Block 3	> 150,000 kWh	$0.1029	$/kWh
Net Produced Energy			
Renewable Generation Credit		$(0.0990)	$/kWh
Grid Usage Charge		$0.0108	$/kWh
Demand			
Block 1	≤ 300	$4.10	$/kW
Block 2	> 300	$6.16	$/kWh
Energy Assistance	Charges as found in EAP Tariff. See General Provision #6.		$/kWh
Energy Charge Adjustment	Charges as found in ECA Tariff. See General Provision #6.		$/kWh

General Provisions

1. The minimum monthly charge, under this tariff, shall be per the Service Access Charge, as found in Charges (Credits), per billing period or prorated if service is provided for less than a full billing period.

2. A surcharge or credit may be applied to each billing for service under this tariff to reflect increases or decreases in cost of power subject to Member Services Policy 29 – Rate Design and Tariff ECA – *Energy Charge Adjustments*.
3. Member agrees to allow the cooperative, at its discretion, to install automatic load management controls.
4. Primary end-use for residential purposes shall be served under this tariff.
5. Summer Block is defined as May billing period through September billing period; Winter Block is defined as October billing period through April billing period.
6. Energy Assistance Charge and Energy Charge Adjustment shall be applied to all energy (kWh) Consumed Energy in the billing period.
7. Net Consumed Energy shall be charges applied to all energy (kWh) consumed at the time where consumption exceeds production. This energy shall be measured at the interconnection meter.
8. Net Produced Energy shall be credits and charges applied to all energy (kWh) produced at the time where production exceeds consumption. This energy shall be measured at the interconnection meter. The sum of all credits and charges totals to a credit.
9. Services installed, commissioned, and energized prior to March 31st, 2022, may remain on the Legacy Renewable Energy Rider method for interconnected DER facilities provided the cooperative has been notified on or prior to March 31st, 2022.
10. Services billed on the Legacy Renewable Energy Rider shall continue using that Legacy Renewable Energy Rider until one of the following conditions has been met:
    - the service is transferred to another member;
    - an executed agreement to be bound by this tariff;
    - an executed agreement requiring participation in this tariff; or
    - after June 30th, 2029.
11. Wholesale Purchased Power (charge or credit) is the annual blended per kWh charge for OPALCO's cost of wholesale power from the mainland suppliers.
12. Renewable Premium includes costs for reduced load on the grid, an environmental credit, and an implementation phase-in credit.
13. Services utilizing this tariff shall not revert to legacy tariff methodology.

Tariff P – Pump Service

Availability
Available to all members, subject to the General Provisions hereunder.

Type of Service
Single-phase, at available secondary voltage, equipment subject to automatic load management controls.

Application
Service for exclusively pumping water for domestic use and/or irrigation.

Charges (Credits)

Charge (Credit) Type	**Charge (Credit) Amount**		
Service Access		$45.23	$/billing period
Energy			
Block 1	≤ 370 kWh	$0.1204	$/kWh
Block 2	371 - 5,000 kWh	$0.0965	$/kWh
Block 3	> 5,000 kWh	$0.1172	$/kWh
Demand			
Block 1	First 20 kW (Flat Rate)	$1.26	$/billing period
Block 2	> 20 kW	$3.99	$/kW
Energy Assistance	Charges as found in EAP Tariff. See General Provision #5.		$/kWh
Energy Charge Adjustment	Charges as found in ECA Tariff. See General Provision #5.		$/kWh

General Provisions
1. The minimum monthly charge, under this tariff, shall be per the Service Access Charge, as found in Charges (Credits), per billing period or prorated if service is provided for less than a full billing period.
2. A surcharge or credit may be applied to each billing for service under this tariff to reflect increases or decreases in cost of power subject to Member Services Policy 29 – Rate Design and Tariff ECA – *Energy Charge Adjustments*.
3. Member agrees to allow the cooperative, at its discretion, to install automatic load management controls.
4. All pumps served under this tariff shall be metered separately.
5. Energy Assistance Charge and Energy Charge Adjustment shall be applied to all energy (kWh) Consumed Energy in the billing period.

Tariff EAP – Energy Assist Program Rider

Availability

Energy Assist Credit is available to low-income members, subject to the General Provisions hereunder, served under the current Tariff R *Residential Service*, and the provisions therein.

Type of Service

Electric service under the current Tariff R *Residential Service*.

Application

Residential homes with year-round low-income occupants being served by a standard residential service.

Charges (Credits)

Charge (Credit) Type	**Charge (Credit) Amount**		
Energy Assistance		$0.00079	$/kWh
Energy Assist			
	Household Size		
	1	($32.67)	$/billing period
	2	($38.91)	$/billing period
	3	($45.15)	$/billing period
	4	($51.39)	$/billing period
	5	($57.63)	$/billing period
	6+	($63.87)	$/billing period

General Provisions

1. The minimum monthly credit, under this tariff, shall be per the Energy Assist Credit, as found in Charges (Credits), per billing period or prorated if service is provided for less than a full billing period.
2. The Energy Assist Credit is pending available funding through the Energy Assistance Charge in each related tariff, and other funding sources as approved by the Board of Directors.
3. Energy Assistance Charge shall be applied to all energy (kWh) Consumed Energy in the billing period under all tariffs.

Tariff LR – Line Retention

Availability

Available for individual services where the primary and transformer only serve one member and the removal of the equipment will not affect the service to other members, and/or no service has been taken for a period of twelve (12) months.

Type of Service

Single-phase, at available secondary voltages.

Application

Payment of the line retention rate will ensure that the facilities remain in place for future use.
Charges (Credits)

Charge (Credit) Type	Charge (Credit) Amount	
Service Access	$45.23	$/billing period

General Provisions

1. The minimum monthly credit, under this tariff, shall be per the Energy Assist Credit, as found in Charges (Credits), per billing period or prorated if service is provided for less than a full billing period.
2. OPALCO shall retire and/or remove facilities that have been idle for greater than twelve (12) months.
3. Payment of the line retention rate will ensure that the facilities remain in place while service has this tariff applied.
4. If OPALCO removes any equipment pertaining to the service while under this tariff, OPALCO shall reinstall the facilities to provide the same service at the time this tariff was applied.
5. Members who have discontinued service for a period of twelve (12) months or have made a formal request for service and have not connected to the system after a period of twelve (12) months are subject to the line retention rate, provided that OPALCO has determined that the facilities are causing ongoing expenses, such as line losses or line maintenance to the system.

Tariff POL – Private Outdoor Lighting

Availability

New service under this tariff is not available after March 1, 1998. Those members receiving service under this tariff prior to March 1, 1998 may continue to do so.

Type of Service

OPALCO will own, maintain and operate suitable fixtures on brackets, with refractors and controls, and supply energy for lamps at locations agreed upon with the member, the service distance not to exceed 150 feet/2 wire, or 300 feet/3 wire.

Application

Non-metered or metered street, yard or security lighting service.

Charges (Credits)

Charge (Credit) Type		**Charge (Credit) Amount**	
Billing		$2.91	$/billing period
Fixture		$13.12	$/billing period
Light			
100 Watt or Equivalent		$4.83	$/billing period
Block 2		$9.80	$/billing period

General Provisions

1. The minimum monthly charge, under this tariff, shall be per the Service Access Charge, as found in Charges (Credits), per billing period or prorated if service is provided for less than a full billing period.
2. All lamp replacements and other maintenance will be provided by OPALCO, except that lamps and fixtures broken by vandalism will be charged to the member.
3. The member shall notify OPALCO if a lamp does not operate. OPALCO agrees to repair lamps as soon as possible, but, in any event, within five (5) working days.
4. A timing device and/or photo electric cell may be installed by OPALCO in order to limit the time interval that the lamp is turned on each night.
5. During the periods of energy shortage, lamps may be disconnected by request of either the cooperative or member, with no charge to member. The member will not be charged for the period the light has been disconnected.

Deposits and Fees

Description	Amount
Description	**Amount**
New Members	
Membership Fee (refundable)	$5.00
Deposits (refundable)	
Residential/Residential TOU	$200.00
Commercial (Small and Large)	TBD by OPALCO*
**Surety bond required in amount of deposit*	
New or Transfer Service	$25.00
Returned Payment Charge	$30.00
Credit Card Process Fee (per transaction)	$2.00
Late Payment Charge	5% of current balance
Disconnect/Reconnect Fees	
Disconnect Notice	$10.00
Door Tag	$50.00
Reconnect (after Disconnect for Non-payment	
During OPALCO business hours	$75.00
Outside of OPALCO Business hours	$150.00
Seasonal Reconnect*	
During OPALCO business hours	$250.00
Outside of OPALCO Business hours	$400.00
**after disconnected for two (2) or more consecutive billing periods*	
Member Caused Outage	Actual Cost
Meter Seal Breakage	$100.00
Meter Test Fee** (at members request)	
Performed by OPALCO	$100.00
Performed by other qualified person	Actual Cost**
***OPALCO will refund cost of meter testing if proven in error by more than two percent (2%)*	

Tariff ECA – Energy Charge Adjustment Rider

A variable true-up adjustment (surcharge or credit) will appear as a line item on member bills to reflect increases or decreases in the revenue and power sales due to weather. The adjustment amount will be solely based on revenue variance and power costs and calculated by comparing budgeted vs. actual revenue variance and power costs per kWh sold. The purpose of the ECA is to address the lack of financial predictability in weather forecasting for kWh sales and revenue. The ECA includes two adjustment mechanisms:

1) An automated monthly reoccurring true-up (surcharge or credit) to be applied to each member billing on a kWh basis, which adjusts for increases or decreases in the actual revenues collected and cost of power purchased as compared to the budgeted revenues collected and cost of power purchased per kWh sold (see below for calculation); and
2) On an as-needed basis and subject to board approval, a variable mechanism that balances the fluctuation in revenues to meet strategic directives.
3) An emergency adjustment to account for material but unpredictable costs such as storm damage that must be approved by the board on a case-by-case basis.

Monthly ECA Factor

The automated monthly charges on member bills shall be increased or decreased on a uniform per-kWh basis computed monthly as follows:

$$ECA = \frac{(Rev_B - Rev_A) + (P_A - P_B)}{kWh_E} + \frac{Uncollected}{kWh_E} + Emergency\ Ajustment$$

The figures for the above variables can be found in Board approved budget and in the financial statements, and on the Sales and Usage Report.

Where:

ECA	Energy Cost Adjustment ($/kWh) to be applied to energy sales for the billing period. The ECA shall be capped at $0.01/kWh excluding the Emergency Adjustment.
kWh_E	Total estimated energy sales for the billing period the ECA will be applied.
Actual Power Cost	Total purchased power cost from all suppliers for the prior month billing period.
Budgeted Power Cost	Total estimated cost of purchased power from all suppliers for the prior month billing period.
Uncollected	Difference in the total ECA revenue collected from the prior month and the total ECA calculated collection for the prior month. $Uncollected = ECA_P * kWh_A$
ECA_P	Energy Charge Adjustment from the prior month billing period as charged/credited.
kWh_A	Total actual energy sales for the prior month billing period the ECA was applied.
Emergency Adjustment	A board approved $/kWh charge to account for material but unpredictable costs. Approved on a case-by-case basis.

Tariff EC – Energy Conservation Charge Rider

Availability

Service under this Rider shall be available in all territory served by the cooperative (OPALCO) and shall be subject to OPALCO's established tariffs and policies. This Rider is an optional and voluntary tariff available to members who take service under any rate schedule for eligible energy efficiency improvements (upgrades) within the OPALCO service territory. It shall not be a requirement that the structure be all-electric. Projects that address upgrades to existing buildings deemed unlikely to be habitable or to serve their intended purpose for duration of service charges will not be approved unless other funding can affect necessary repairs.

Application

A monthly Energy Conservation (EC) charge will be assigned to any meter located where upgrades are installed utilizing OPALCO on-bill financing program. Members occupying the location of the meter shall pay the EC charge until all OPALCO costs have been recovered. OPALCO will recover the costs of its investments, including any fees allowed, in this tariff. Charges will be set for a duration not to exceed the estimated life of the pre-approved upgrades or the length of a full parts and labor warranty, whichever is less and in no case longer than ten (10) years. The EC charge, and duration of payments will be included in the Efficiency Conservation Agreement between OPALCO and the member.

General Provisions

ENERGY CONSERVATION AGREEMENT TERMS

1. No up-front payment is required by participating members. The initial cost of approved energy efficiency measures will be paid by OPALCO, up to the maximum amount established for each EC measure.
2. The repayment obligation shall be assigned to the meter at the premises and will survive changes in ownership and/or tenancy.
3. Until cost recovery for upgrades at a meter location is complete, the terms of this tariff shall be binding on the metered structure and any future member who shall receive service at that location.
4. Program costs shall be recovered through a monthly EC charge on the utility bill.
5. Without regard to any other OPALCO rules or policies, the EC charge shall be considered as an essential part of the members bill for electric service, and OPALCO may disconnect the associated electric meter for non-payment of EC charge under the same provisions as for any other electric service.
6. OPALCO may make an incentive payment for program participation that is less than or equal to the value of the upgrades to the Cooperative.
7. A member's and landlord's (if applicable) signature on the EC Agreement shall indicate acceptance of this tariff.
8. OPALCO will be responsible for estimating resource savings and developing a Conservation Plan upon which the EC charge will be based, detailed in this tariff.
9. Once OPALCO's costs for upgrades at a specified location have been recovered, the monthly charge shall no longer be billed.

Conservation Plan

The Conservation Plan (the Plan) will be developed by OPALCO and specify measures eligible for financing. The Plan includes:

- EC Charge – The charge to be included on Member's utility bill will be based on the actual cost of the proposed measure(s). The Cooperative will be solely responsible for calculating the EC charge utilizing standard amortization methods. To the extent applicable, OPALCO will incorporate County recording fees and OPALCO rebates or discounts into the calculation of the EC charge.
- The annual interest rate used to calculate the EC charge shall be no more than two percent (2%).
- Number of Payments – The number of monthly periods for which the EC charge will apply at the premises. Unless otherwise specified, the EC charge shall not exceed the estimated life of the measure or ten (10) years, whichever is less.
- Project Cost - the total actual cost of the energy conservation project being financed, for the purpose of calculating the EC charge. Project cost will include (1) the final amount billed by the contractor, and paid by OPALCO, subject to the terms of this policy and the EC Agreement, (2) recording fees charged by the County, and paid by OPALCO, (3) optional decommissioning of a fossil fuel system and (4) an energy audit (if applicable). Energy snapshot fees may not be included in the Project Cost.
- Estimated Resource Savings – The modeled change(s) in costs of resources consumed at the premise attributable to the efficiency measure(s) proposed. The Cooperative will be solely responsible for savings estimates.

Approved Contractor

Should the member determine to proceed with implementing the Plan, OPALCO shall determine the appropriate monthly charge as described above. The member shall sign the EC Agreement and select a certified contractor.

Quality Assurance

When the energy efficiency upgrades are completed, the contractor shall be paid by OPALCO, following on-site, telephone, or written report inspection and approval of the installation by the member and cooperative. OPALCO does not guarantee the performance of the upgrade appliance or the quality of work of any contractor.

Uneconomic Measures

A member may elect to "buy down" the cost of implementing an efficiency measure so that the EC charge will be less than the average estimated monthly savings. In this case OPALCO must be notified in advance of the payment to appropriately process the payment.

New and Existing Structures

A member may utilize this Rider to install high efficiency equipment or measures in new structures. At its sole discretion, OPALCO may determine a property is not eligible for the program and does not qualify for this Rider if:

- The structure has an expected life shorter than the payback period, or
- The structure does not meet applicable public safety or health codes.

Responsibilities

Responsibilities, understandings, and authorizations of members, OPALCO, landlord (if applicable) and Participating Contractor shall be outlined in written agreements, notifications and disclosures/consents.

Transition in Roles

Payments due pursuant to an Energy Conservation Agreement are based upon the meter serving each property participating under this tariff. All responsibility for outstanding EC obligations and payments belong to the member or any successor party to the member, landlord or tenant change, including any subsequent owner, tenant, or otherwise. Note, to the extent necessary, each member maintains all disclosure obligations. For example: If a person sells a home, they are required to notify the purchaser of the tariff obligation. Failure to provide such notification shall not affect the cooperative's ability to continue billing pursuant to this tariff.

Other

1. This Rider only applies to measures permanently installed as fixtures at the premises. Portable efficiency products do not qualify under this Rider. OPALCO will solely determine eligibility of measures or products.
2. Premises in which the measures will be installed must be permanently anchored to a foundation.
3. At its sole discretion, OPALCO may determine the maximum program investment in any year.
4. OPALCO will determine the eligibility of a member based under the member's bill payment history with the cooperative, projected energy savings and program capacity. Service under this Rider shall be available in all territory served by the cooperative (OPALCO) and shall be subject to OPALCO's established tariffs and policies. This Rider is an optional and voluntary tariff available to members who take service under any rate schedule for eligible energy efficiency improvements (upgrades) within the OPALCO service territory. It shall not be a requirement that the structure be all-electric. Projects that address upgrades to existing buildings deemed unlikely to be habitable or to serve their intended purpose for duration of service charges will not be approved unless other funding can affect necessary repairs.

Tariff LRR – Legacy Renewable Energy Rider

Availability

Available to all services utilizing Member Service Policy 13 for interconnection of distributed energy resource (DER) facilities, subject to the General Provisions hereunder. DER facilities include solar, wind, hydro, and battery storage.

General Provisions

1. This rider shall be applied to the primary tariff utilized for the service utilizing Member Service Policy 13.
2. Energy produced that exceeds consumption shall be used to directly offset energy consumed that exceeds production within the billing period.
3. Energy produced that exceeds the energy consumption for the billing period shall be carried to the following billing periods until either it is fully offset by consumed energy or March 31. On April 30 of each year, the produced energy that exceeds the consumed energy shall be paid at $0.01 greater than the average wholesale cost of power (See General Provision #4).
4. The yearly average shall be determined each year on March 31 using OPALCO's year-end Rural Utilities Service (RUS) Form 7, Part K, Section (e) Average Cost.
5. The billing adjustments applies to charges for energy consumed only. A member participating in this tariff is subject to the OPALCO tariff under which the member receives service.
6. Produced energy that exceeds consumption shall be applied only to energy usage and not the service access charge. In all cases, the service access charge will apply.
7. If the service has selected the use of "Buy/Sell", general provision 1 and 2 do not apply. All produced energy that exceeds consumption within the billing period shall be credited on a monthly basis at $0.01 greater than the average wholesale cost of power (See General Provision #4).
8. Services installed, commissioned, and energized prior to March 31st, 2022, may remain on this tariff for interconnected DER facilities provided the cooperative has been notified on or prior to March 31st, 2022.
9. Services billed on this legacy tariff rider shall continue using this tariff rider until one of the following conditions has been met:
    - the service is transferred to another member;
    - an executed agreement to be bound by this tariff;
    - an executed agreement requiring participation in this tariff; or
    - after June 30th, 2029.

NWPCC Responses to OPALCO Questions

Eighth Power Plan

At the October Board Meeting, staff provided background information and a series of questions concerning the Eighth Power Plan. Below are their written responses to OPALCO's questions.

Council Staff Response to OPALCO Board Questions

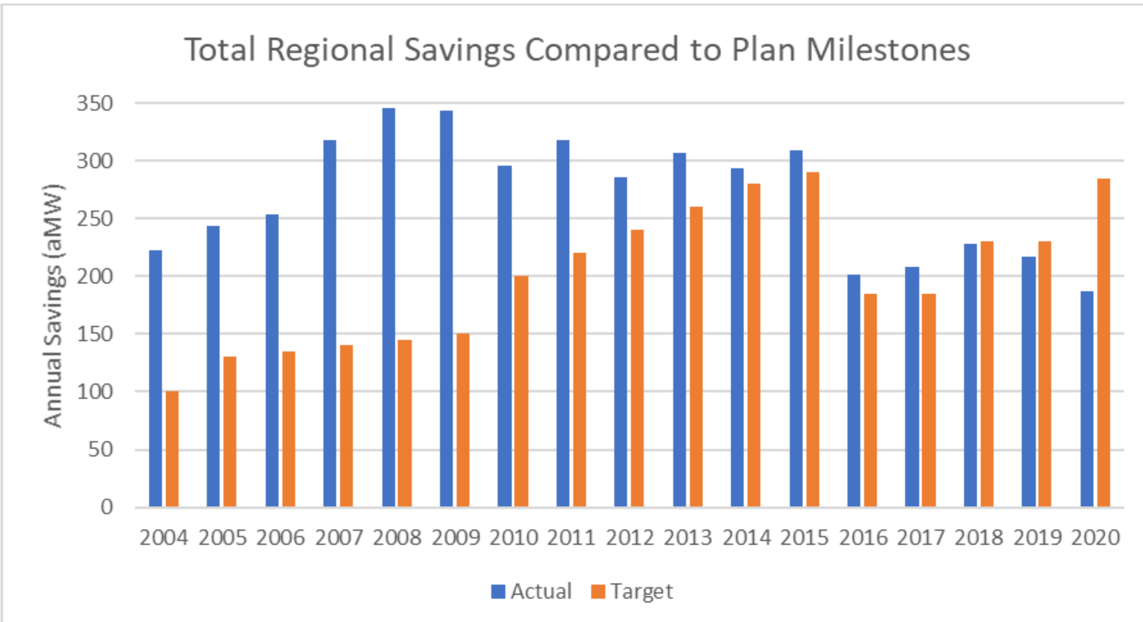
10/27/21

1. **Previous NWPCC Power Plans have had projections that proved too optimistic, particularly around energy efficiency.** In the 2021 Power Plan, that optimism has spread to nearly every aspect of the plan. Given the numerous recent studies that forecast significant northwest resource adequacy issues (see discussion below, 8 October 2021 Page 2 of 13 and references at end of document), what drove this optimism, and how confident is NWPCC of their projections? Texas, California, and Europe are recent examples of what can go wrong when demand exceeds supply. It is a cautionary tale. While we can hope for the best, we must plan for the worst. This is document aspires to be a plan, not a hope. So, it must embrace a credible comprehensive worst-case analysis. The risk of not getting this right will impact the regional economy, safety, and cost of energy, through the rolling blackouts and unplanned outages during peak weather events – hot, cold, fire, etc.

Council staff responses are provided in blue:

The Council's resource strategy is not a projection of what *could* happen, it is a strategy of what *should* happen - given the uncertainties and risk in the future - in order to maintain an adequate, efficient, economic, reliable, power supply and meet federal and state policies. The Council develops its analysis through planning under uncertainty – by anticipating ranges of future demand, fuel prices, hydro conditions, etc. – and uses scenarios to help inform questions about what the future could look like under a given set of circumstances. Analysis that considered multiple risks like market supply uncertainty, varying loads, hydro runoff and generator availability suggested that the system's adequacy needs can be addressed via the recommended regional resource strategy. Worst case analysis would surely come up with situations that could not be met. Traditionally, regional entities have not wanted to invest to have a system so robust to stand up to the "worst possible" case. The current adequacy standard for the Council is a 5% LOLP. A higher standard would likely result in a more expensive system. A standard that would preclude any planned shortages would be significantly more expensive.

The region as a whole has exceeded the Council power plan annual energy efficiency targets for the Fifth, Sixth, and most of the Seventh Power Plan. In 2018 and 2019, the region missed the annual target for the first time, but cumulatively were still exceeding the Seventh Plan's action plan target until 2020 – when the region fell below the target. Reasons for the region not currently meeting EE targets include the fact that much of the low cost, easy to implement efficiency (e.g. efficient lighting) has been achieved and EE is getting more expensive – yet budgets are not keeping pace. In addition, the Covid-19 pandemic has had a negative effect on the deployment of some energy efficiency measures, impacting the achievements in 2020.



2. **The 2021 Power Plan doesn't factor hydro capacity decreasing due to increasing spill projections, seasonal timing of run-off and potential LSRD removal.** For example, Oregon is seriously considering initiating a 24/7/365 spill of hydro, which will reduce renewable hydro capacity that would otherwise be used to firm solar, wind, and meet baseload. (See PPC Fish & Wildlife assessment)

Correct. The Council models constraints as described by the Council's Fish and Wildlife Program, and works with Bonneville and the Corps to get appropriate hydro regulation and constraints. In the 2021 Power Plan, the Council adjusted our hydro runoff projections for climate change flows which do not account for seasonal changes in flows.

3. **BPA Export / Import assumptions "as existing" and are not projected, even as BPA is looking to the secondary market to "maximize the value of the hydro system"** (see EIM and EDAM)

The Council worked closely with Bonneville and used assumptions they provided to support our analysis of the Bonneville portfolio.

4. **New Renewable Generation Projects assumptions are overly aggressive that 3,500 MW will come to market as projected (given capital, siting, & permitting constraints / resistance).** See discussion below on land use and environmental issues. Note: The 8th PP renewable energy growth assumptions follow individual state estimations, which are essentially unfunded state mandates. NIMBYism is also rising - e.g. environmental resistance by Sierra Club (see also: Wind

Power Project Rejection Database). In short: Top down reports such as the 8th Power Plan vs. bottoms up summations such as the WA State IRP report show significant disagreement between expectations and committed/planned resources. There is clearly a mismatch in top-down vs bottoms up estimates on Conservation and Demand Response programs. Tops down (8th Power Plan) appears to be overly optimistic given the individual utility's IRP submittals. In addition, difficulty in estimating regional power imports and exports usually results in them being ignored, or frozen at current levels. There are only rough estimates on the quantity, cost, location, and timing of construction of new intermittent renewable generation and storage resources. When all known planned or committed resources are considered, there still appears to be adequacy issues, with unacceptable LOLP's. Quote of note: "To be clear, this forecast does''t represent a forecast of power plants the Council expects will be built in the future. Rather, it shows what we estimate it would take to meet all the various requirements put on Western electric utilities." (Page 6-44)

The 2021 Power Plan's resource strategy recommends at least 3,500 megawatts of renewables in order to maintain an adequate, efficient, economic, and reliable power system. Council staff analysis of projects in the development pipeline, IOU resource solicitations, and utility integrated resource plans suggest that this number is conservative compared to what is planned to occur by 2027.

In addition, the Council did recognize the challenges inherent with a large-scale build of renewable resources, "including long-term firm transmission access, land-use regulations and moratoriums, and uncertainty over the cumulative effects of significant renewable development on the environment and cultural resources." See new solar and wind opportunities and challenges in the supporting documentation for further discussion including potential solutions like least-conflict siting.

5. **Energy Efficiency / demand response targets remain optimistic and will require sizable grid upgrade to be realized.** Quotes of note: "In recent years, with all the accomplishments and increasing efficiency levels, the future amount of low-cost efficiency available has diminished." (Page 5-29) "Additionally, in the current contracts, many Bonneville customer utilities see little value in pursuing demand response and are limited in the ability to provide a demand response resource to another utility, both within and external to the pool of Bonneville customer utilities. In future contracts, Bonneville should consider provisions supporting its customer utilities' development and export of demand response resources." (Page 8- 93)

It is not clear what is meant as a "sizable grid upgrade" as applicable to energy efficiency, as EE is a behind-the-meter resource that, in fact, may defer transmission and distribution system upgrades. The resource strategy does not have a demand response target, per se. The recommendation is for utilities to explore low cost, frequently deployable DR, in their resource planning. Products such time-of-use (TOU) and demand voltage regulation (DVR) are two examples that can serve that need. There may be a grid investment required (although DR can also defer transmission and distribution upgrades); however, many utilities already have the needed capability (e.g. AMI is needed for TOU, but currently more than 80% of all residential meters in the region are AMI). The citation in the plan about Bonneville utilities lack of DR value is primarily contractual and not technical. Under current contracts, it is challenging for BPA customer utilities with limited need but significant DR capability to "trade" that value with other utilities that have need but limited capability. (For further discussion on this topic, see the August 21, 2019 Demand Response Advisory Committee meeting)

6. **The 2021 Power Plan doesn't address the numerous transmission challenges facing the region. How can resource adequacy be planned for if new transmission assets can't be built?** Does the Council support and recommend that BPA participate in the establishment of a RTO dedicated to the PNW to help solve the many transmission related challenges we are facing? Quote of note: "The Council in our work assumes that the transmission planning organizations and utilities will work together to ensure appropriate investment is made into the transmission system to at a minimum maintain the current ability to deliver electricity around the West. While we do not study expansion of the transmission system in this plan, we recommend the region work with the transmission planning organizations to explore the costs and benefits of doing so." (Page 4-23)

This is true to some extent, we limit our analysis of operational challenges to the current transmission build. The existing transmission system does seem stressed/congested in many of the simulations showing extremely large renewable builds especially long term, and it is likely that new transmission would be helpful in alleviating this stress. One way the Council does acknowledge this issue in our planning simulations is to credit certain customer or conveniently sited resources, like energy efficiency or battery storage, for deferral of new transmission assets. The power plan analysis showed that regional coordination even under the existing transmission system can reduce the amount of reserves the region would have to hold and make the system run more efficiently from a variable cost perspective. Additionally, analysis seemed to support on a broader basis that a more diverse and small buildout of resources would be supported by more coordination in the WECC.

The Council did an analysis of regional transmission utilization and concluded that it is entirely possible – and common – that a given transmission path could be fully contractually encumbered on a long-term firm basis, while still having substantial available physical capacity most or all hours of the year. In short, contractual encumberment is a commercial issue, not a physical capacity issue. In power planning, a presumption that resources can only be built where there is available long-term firm contract capacity can lead to substantially increased costs through expansions and upgrades to the existing transmission infrastructure and excessively limiting resource potential based on the absence of available firm transmission. This can lead to the potential of excluding least-cost resource development and/or recommending unnecessary transmission expansion by only including resources paired with long-term firm contract availability. On the other hand, a presumption that resources can be built wherever there is physical capacity can overstate resource potential and operational transmission capability.

This analysis, and other findings from the plan, led to a recommendation in the power plan for "the region's transmission providers work with utilities, load serving entities, NorthernGrid, and others to develop a comprehensive review of the existing state of the transmission system, research potential short-term and long-term solutions to alleviate new resource development barriers while balancing existing long-term contracts and compensation to transmission providers, and explore the potential benefits of implementing a regional transmission operator in the Pacific Northwest."

7. **An examination of individual IRP's shows mid-2020's and beyond capacity shortages for many utilities**. **The nearly universal response is "market purchases" to meet the demand.** There is no clear definition of "the market" in terms of who is building what, where, when, and at what cost. There appears to be a belief that EIM, EDAM, and RA programs will somehow produce the "correct" investments in generation, storage, and transmission infrastructure. There is also considerable disagreement about and concern for CAISO's perceived excess control of evolving market structures. Will the PNW wind up paying CA prices for energy as a result?

The Council's power plan is a regional plan, not a summation of individual utilities, and therefore when the plan calls for market purchases, it is region-wide – and not double counting.

Due to the fact that other regions like California likely will have to build excess renewables like solar and wind to meet their state standards and the fact that hydropower has some capability to shift generation throughout the day, there likely will be an opportunity to take advantage of cheap surplus power during some parts of the day. However, there will likely be some wholesale price pressure during other parts of the day when renewables are less available, but the hydro system will likely buffer the NW exposure. As alluded to, participation in the EIM, EDAM and RA should benefit the NW in terms of taking part in broader resource diversity as long as those markets are well structured. In an era with so many policies, non-participation in at least some of those market processes seems more likely to result in higher costs for most utilities.

8. **There is frequently mentioned the need for a PNW wide RTO, however, critics just as frequently point out previous failures to create such an entity.** Yet, analysts say the problem is unlikely to be solved by hundreds of utilities and 10's of Balancing Authorities somehow producing an optimal market and physical solution. 8 October 2021 Page 3 of 13

The Council encourages the utilities and Bonneville to work together to improve coordination inside the region and with our neighboring regions. The plan does not call for a PNW wide RTO.

9. **Various reports paint a picture of "double (or multiple) counting" of the use of renewable resources.** For example, WA State and CA both claim to use "50% or more" of future Montana and Wyoming wind resources.

The Council's power plan is a regional plan, and therefore there is no double counting.

10. Load Growth estimates and generation resources needed to meet that load vary. Here are three examples of widely diverging views on load growth and generation: Northwest Regional Forecast of Power Loads and Resources 2021 through 2031- PNUCC "Nearly 100 regional utilities, making up 55% of the load, are forecasting annual energy load growth at under 0.5% per year, including 14 utilities expecting load decay. Most of the forecasted growth comes from utilities in the high growth group (1.5% or more per year). Much of that growth hinges on large new and growing industrial customers in the Northwest." 2021 Energy Strategy Transitioning to an Equitable Clean Energy Future – WA State Dept of Commerce "Total demand for electricity nearly doubles by 2050 in the Electrification Scenario and expands significantly in the other scenarios. Supplying this electricity from clean electricity sources is cheaper than other alternatives such as decarbonizing fuels. Washington's electricity supply is already 69% clean because of the state's significant hydro resource, however we assume there is no opportunity to expand hydroelectricity supply in the future, so wind and solar resources provide the additional energy needed. In 2020, Washington is a net exporter of energy. As renewable generation fills the state's additional energy needs, Washington becomes a net importer, bringing in 43% of its electricity by 2050 in the Electrification Scenario, 36% of which comes from Montana and Wyoming wind. To understand where imports into Washington derive from throughout the West, please see page 39 of the technical report in Appendix B. The lower relative cost of these out-of-state resources versus in-state opportunities limits the growth of new renewable capacity in state until 2040 when Washington starts to build solar and offshore wind." Washington State Electric Utility Resource Planning 2020 Report Pursuant to RCW 19.280.060" – Washington State Department of Commerce, December 2020 "Hydropower will remain the dominant source of electric for Washington utilities over the 10-year forecast period. Generation from coal-fired electricity will decrease in the forecast period that will increase reliance on natural gas-fired generation. Base-year aggregated state utility load has remained in a narrow band over the period from 2008 through 2020. Load growth forecasts by utilities for the five and 10-year out points have been trending down with each successive Commerce Utility Resource Plan report. The statewide aggregate growth in electricity demand is expected to be moderate, and most of this growth will be offset through energy conservation programs operated by utilities. However, several utilities with surplus generating capacity and very inexpensive electricity (Chelan, Douglas, and Grant PUDs) are forecasting very high load growth rates over the next 10 years. The report shows that short and long-term contracts make a smaller contribution to total resources in the base year (2019), but they are forecast to make larger contributions in the five and 10-year forecasts than was seen in the 2018 utility resource report. The Pacific Northwest Utilities Conference Committee 2020 Regional Forecast report reveals a projected electricity deficit for the Northwest starting in 2024 (283 aMW) and continuing to grow through the end of the 10-year planning period (3,200 aMW). PNUCC identifies a large number of planned resources in the region, but because they have less certainty from a financial or regulatory standpoint, they therefore are not

included in the forecast. The region's premier planning body, the Northwest Power and Conservation Council, evaluated the adequacy of the Northwest electric power supply in 2020 and concluded that resources are not expected to meet its adequacy standard after 2020. Resources are considered adequate when the loss-of-load probability (LOLP) is less than 5 percent. However, with the planned retirements of Boardman and Centralia 1 at the end of 2020, the LOLP will reach of 7.5 percent in 2021 and will no longer meet the Power Council's adequacy standard. The retirement of the Hardin coal-fired power plant and the Klamath Hydro facility in 2021 were forecast to raise the LOLP to 8.2 percent by 2024. The Council noted that other power plant retirements announced for later in the decade would raise the LOLP value further if replacement resources are not brought online in a timely manner." Conclusion: Individual utilities, especially those without wholly owned generation resources, are in a planning period of extreme uncertainty about the cost and reliability of their future power supply. Boards and staffs of these utilities need to continually educate themselves on the rapidly evolving scenarios and consider the implications for ongoing investments in their infrastructure.

The Council considered a wide range of potential load growth. We do not plan for a single forecast. We forecast load growth based on prevailing economic forecasts vetted with the state economists. We also ran scenarios, such as our Pathways to Decarbonization scenario, where we examined structural changes to load growth consistent with electric load being on a trajectory to double by 2050. The recommendations in the plan focus on balancing near-term action with long-term uncertainty.

11. **The plan should include a realistic worst-case analysis, to understand what could go wrong, and then plan for how to mitigate, properly fund, and implement, rather than revise the plan as needed - that won't work.** Quote of note: "The 2021 Northwest Power Plan includes many recommendations to the regional and to 8 October 2021 Page 4 of 13 Bonneville. We recognize that the regional power system is in an extraordinary time of change with many uncertainties associated with future system operations." (Page 6-42)

The regional adequacy standard of 5% loss of load probability is in no way a worst-case scenario. However, planning exclusively for a worst-case scenario may be economically prohibitive. The Council did model a number of different risks and potential resource strategy options to address those risks – including scenarios requiring substantial resource additions to maintain resource adequacy. The Council considered all these when laying out the resource strategy in the plan.

12. **There is a lack of transparency (at least in the available reports) on the models used, assumptions made, and datasets utilized to prepare the reports and conclusions.** Various reports are given credibility and authority differently by different special interest groups.

The Council devoted a substantial number of meetings of our system analysis, resource adequacy, generation resource, demand response, load forecast, natural gas, and conservation resource advisory committees precisely to the purpose of exposing to the public the details of the models used and the inputs, data and assumptions used. In addition, the Council held a several-day technical workshop August 4-6, 2021 devoted entirely to this end. The development of the Council's power plan is a very public process, with numerous advisory committee meetings, Council Meetings, and outreach to stakeholder groups. Council staff is happy to meet with organizations and explain any of the modeling or assumptions upon request. Additionally, if there is information not included in the supporting material that is desired please request it and we can augment the current material.

OPALCO
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OPALCO's comments to NWPCC Draft Eighth Power Plan

OPALCO Comments on NWPCC Power Plan

OPALCO has reviewed the draft NWPCC Power Plan and offers its comments. These comments are offered at a time when the northwest region is accelerating a rapid decarbonization of the grid as well as decarbonizing the engines of the economy – eg. transportation, industry, heating – the largest sources of greenhouse gas emissions.

As the noted American economic and energy thought leader Jeremy Rifkin predicted in 1980, once we grasp the enormous implications of shifting the energy base of society from concentrated (fossil fuels) to dispersed (solar, wind), it becomes apparent that our existing energy infrastructure is completely unsuited to a solar/wind future, even with hydro for firming. It will require vast amounts of land, and thousands of miles of new transmission infrastructure to move it from source to cities. An enormous task is ahead of us. It can be done, but...

Exec Summary

- **Demand for electricity will double by 2050**, but supply is shrinking rapidly, driven by rapid decarbonization to reduce climate impact. (Washington 2021 Energy Strategy)
- **This reduced headroom will lead to near-term rolling blackouts and price increases** during extreme weather events, similar to what we have seen unfolding in Texas and California. Refer to the detailed reporting (discussed below) on how climate disruption requires a higher level of thinking, modeling and design of future energy systems that are reliable during increasingly unpredictable climate-driven extreme weather events – heat waves, cold snaps, regional firestorms – exemplified by recent extensive outages in California, the northwest and Texas in 2021.
- **It will take years, money, land, transmission and enlightened policy to meet the need** for new clean energy.
- **While there has been hope that adding new solar, wind and storage resources to the regional portfolio will reduce the need for hydro, it is clear from the WA *2021 Energy Strategy* and the NWPCC *Power Plan*, that they both depend on all current hydro resources remaining through 2050.**
- **Current Northwest regional strategies are essentially unfunded mandates with no detailed plan**. The NWPCC *Power Plan* is not a plan. It is aspirational, lacking detailed objectives, key results, and worst-case analysis that considers the significant schedule risk of solutions that require vast amounts of land to implement.
- **A key near-term strategic action should get the Federal Energy Regulatory Commission (FERC) to establish a Northwest Regional Transmission Organization** (RTO). The Northwest is the only region of the US with no RTO. While most of the demand will be west of the Cascades, most of the generation will be east of the Cascades. **The RTO should be Federally mandated to solve the Pacific Northwest capacity problems first**, and weave together the various stakeholders across WA, OR, ID, MT and WY to ensure **reliable** supplies of power, **adequate transmission infrastructure** and **competitive wholesale electricity prices**. And it can accelerate the deployment of essential transmission capacity to interconnect the network of new solar and wind resources needed to meet the regions doubling power needs. We should get this going ASAP to tap into anticipated Federal infrastructure spending aimed at development of new clean energy resources.
- The western **Energy Imbalance Market** (EIM) can play a central role in helping establish the RTO.

The Northwest Power and Conservation Council (NWPCC)

The Northwest Power and Conservation Council was established pursuant to the Pacific Northwest Electric Power Planning and Conservation Act of 1980 (Public Law 96-501) by the states of Idaho, Montana, Oregon, and Washington. The Act authorized the Council to serve as a comprehensive planning agency for energy policy and fish and wildlife policy in the Columbia River Basin and to inform the public about energy and fish and wildlife issues and involve the public in decision-making.

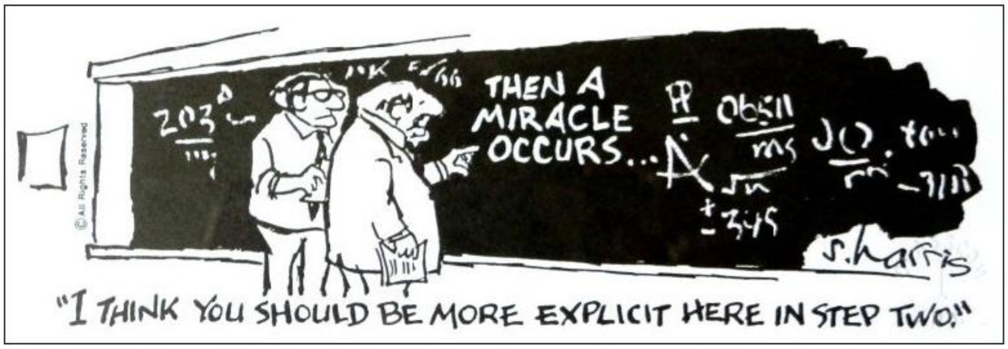
The NWPCC recently released their draft *2021 Northwest Power Plan*, the first overarching plan in five years for how to meet long-term electricity needs with new power resources, energy efficiency, demand response and more. The governments of Washington state and Oregon and public and investor-owned utilities, working together through the Northwest Power Pool, are in the process of figuring out how to implement strategies for the Northwest's power supply that involve little to no new natural gas.

NWPCC Discussion Topics

The *2021 Power Plan* comes across as aspirational, founded on hope rather than grounded in hard realities of developing new resources that depend on new land, transmission, and environmental approval. Plan assumptions are overly optimistic and will translate to increased probabilities of rolling blackouts and loss of load going forward.

This optimism becomes a risk as we implement the various building blocks of the new renewable infrastructure. Each component of the solution has an inherent probability of success in a desired timeline, where each project depends on those projects that proceed it. For example, if there are 10 projects, each with a probability of success of 90%, the overall project probability of success becomes about 35%. This problem of cascading probability of complex projects is compounded when we factor in the wildcards of the climate emergency – extreme weather, heat, cold, fire, drought – that put the grid at risk of Texas/California-style rolling blackouts as demand exceeds supply.

As NWPCC's Ben Kujala, director of power planning observed, "*I don't think anyone is super prepared for a future where we're electrifying everything, just because it's so hard to [prepare]. You would have to invest so much money, and if you're wrong, it would look so bad to go out and spend a bunch of money on something that just doesn't materialize.*"



1. **Previous NWPCC Power Plans have had projections that proved too optimistic**, particularly around energy efficiency. In the *2021 Power Plan*, that optimism has spread to nearly every aspect of the plan, as the region has run out of "low hanging fruit" efficiency measures. Given the numerous recent studies that forecast significant northwest resource adequacy issues (see discussion below, and references at end of document), what drove this optimism, and how confident is NWPCC of their projections? Texas, California, and Europe are recent examples of what can go wrong when demand exceeds supply. It is a cautionary tale. While we can hope for the best, we must plan for the worst. If this document truly wants to be a plan, not a hope, then it must embrace a credible comprehensive worst-case analysis and answer key questions: **What is the deliverable? What is the schedule? Who is responsible?** The risk of not getting this right will impact the regional economy, safety and cost of energy, through the rolling blackouts and unplanned outages during peak weather events – hot, cold, fire, etc. In our discussions with NWPCC, they acknowledge the "*resource strategy is not a projection of what could happen, it is a strategy of what should happen*" and that "*Worst case analysis would surely come up with situations that could not be met*." The Council's adequacy standard is a 5% LOLP. But the plan lacks the detail to understand how this standard will actually be met, with confidence.
2. The *2021 Power Plan* doesn't factor **hydro capacity decreasing** due to increasing spill projections, seasonal timing of run-off and potential LSRD removal. For example, Oregon is seriously considering initiating a 24/7/365 spill of hydro, which will reduce renewable hydro capacity that would otherwise be used to firm solar, wind, and meet baseload. (See PPC Fish & Wildlife assessment). **In communication with OPALCO, the Council acknowledges this.**
3. **BPA Export / Import** assumptions are "as existing," not projected, even as BPA is looking to the secondary market to "maximize the value of the hydro system." (See EIM and EDAM). The Council acknowledges this, saying "*The Council worked closely with Bonneville and used assumptions they provided to support our analysis of the Bonneville portfolio*" but offering no sensitivity analysis regarding impact on the plan due to secondary market pressure. For example, as the western region accelerates the deployment of intermittent solar and wind power, demand for hydro to firm that intermittent portfolio will increase sharply, putting pressure on hydro to meet baseload while firming intermittent solar and wind. How will that growing pressure impact pricing, and resource availability for the northwest region, particularly as the northwest and California decommission existing capacity – e.g. Diablo Canyon provides about 8% of California's power, to firm renewables, and will be shut down in 2025?
4. **New Renewable Generation Projects** assumptions are overly aggressive hoping that 3,500 MW will come to market as projected (given capital, siting, & permitting constraints / resistance). See discussion below on land use and environmental issues. Note: The Power Plan renewable energy growth assumptions follow individual state estimations, which are essentially unfunded state mandates. NIMBYism is also rising - e.g. environmental resistance by Sierra Club (see also: Wind Power Project Rejection Database).
In short: Top-down reports such as the 8th Power Plan vs. bottoms-up summations such as the WA State IRP report show significant disagreement between expectations and committed/planned resources. There is

clearly a mismatch in top-down vs bottom-up estimates on Conservation and Demand Response programs too. Top-down (Power Plan) appears to be overly optimistic given the individual utility's IRP submittals. In addition, difficulty in estimating regional power imports and exports usually results in them being ignored, or frozen at current levels.
There are only rough estimates on the quantity, cost, location, and timing of construction of new intermittent renewable generation and storage resources. When all known planned or committed resources are considered, there still appears to be adequacy issues, with unacceptable LOLP's.
Quote of note: *"To be clear, this forecast doesn't represent a forecast of power plants the Council expects will be built in the future. Rather, it shows what we estimate it would take to meet all the various requirements put on Western electric utilities."* (page 6-44) In the Council's supporting material, they acknowledge these omissions, including *"long-term firm transmission access, land-use regulations and moratoriums, and uncertainty over the cumulative effects of significant renewable development on the environment and cultural resources,"* but offer no assessment or plan for meeting these challenges.

5. **Energy Efficiency / Demand Response** targets remain optimistic.
Quotes of note: *"In recent years, with all the accomplishments and increasing efficiency levels , the future amount of low-cost efficiency available has diminished."* (page 5-29)
"Additionally, in the current contracts, many Bonneville customer utilities see little value in pursuing demand response and are limited in the ability to provide a demand response resource to another utility, both within and external to the pool of Bonneville customer utilities. In future contracts, Bonneville should consider provisions supporting its customer utilities 'development and export of demand response resources." (page 8-93)

6. The 2021 Power Plan doesn't address the numerous **transmission challenges** facing the region. How can resource adequacy be planned for if new transmission assets can't be built? Does the Council support and recommend that BPA participate in the establishment of a RTO dedicated to the PNW to help solve the many transmission related challenges we are facing?
Quote of note: *"The Council in our work assumes that the transmission planning organizations and utilities will work together to ensure appropriate investment is made into the transmission system to at a minimum maintain the current ability to deliver electricity around the West. While we do not study expansion of the transmission system in this plan, we recommend the region work with the transmission planning organizations to explore the costs and benefits of doing so."* (page 4-23) In communications with OPALCO, the Council acknowledges this, saying "*This is true to some extent, we limit our analysis of operational challenges to the current transmission build. The existing transmission system does seem stressed/congested in many of the simulations showing extremely large renewable builds especially long term, and it is likely that new transmission would be helpful in alleviating this stress.*" OPALCO appreciates the Council's recognizing the need to "*explore the potential benefits of implementing a regional transmission operator in the Pacific Northwest.*"

7. An examination of individual IRP's shows mid-2020's and beyond capacity shortages for many utilities. The nearly universal response is "**market purchases**" to meet the demand. There is no clear definition of "the market" in terms of who is building what, where, when, and at what cost. There appears to be a belief that EIM, EDAM, and RA programs will somehow produce the "correct" investments in generation, storage, and transmission infrastructure. There is also considerable disagreement about and concern for CAISO's perceived excess control of evolving market structures. Will the PNW wind up paying CA prices for energy as a result? In communications with OPALCO, the Council acknowledges this, saying that participation in the EIM, EDAM and RA is a precondition to avoid the "*higher costs for most utilities*" while not factoring this into the plan objectives, key results, and timeline.

8. There is frequently mentioned the need for an RTO in the pacific northwest, however, critics just as frequently point out previous failures to create such an entity. Yet, analysts say the problem is unlikely to be solved by hundreds of utilities and 10's of Balancing Authorities somehow producing an optimal market and physical solution. In communications with OPALCO, the Council "*encourages the utilities and Bonneville to work together to improve coordination inside the region and with our neighboring regions. The plan does not call for a PNW wide RTO.*" OPALCO believes an RTO is an essential requirement of the plan's objectives and key results.

9. Various reports paint a picture of "**double (or multiple) counting**" of the use of renewable resources. For example, WA State and CA both claim to use "50% or more" of future Montana and Wyoming wind resources. And as Montana/Wyoming transition from coal to renewables, will they keep their wind power for themselves? The Council tells us their "regional plan" avoids this. We remain skeptical.

10. **Load Growth** estimates and generation resources needed to meet that load vary. Here are three examples of widely diverging views on load growth and generation:
    Northwest Regional Forecast of Power Loads and Resources 2021 through 2031- PNUCC
    "Nearly 100 regional utilities, making up 55% of the load, are forecasting annual energy load growth at under 0.5% per year, including 14 utilities expecting load decay. Most of the forecasted growth comes from utilities in the high growth group (1.5% or more per year). Much of that growth hinges on large new and growing industrial customers in the Northwest."
    2021 Energy Strategy Transitioning to an Equitable Clean Energy Future – WA State Dept of Commerce
    "Total demand for electricity nearly doubles by 2050 in the Electrification Scenario and expands significantly in the other scenarios. Supplying this electricity from clean electricity sources is cheaper than other alternatives such as decarbonizing fuels. Washington's electricity supply is already 69% clean because of the state's significant hydro resource, however we assume there is no opportunity to expand hydroelectricity supply in the future, so wind and solar resources provide the additional energy needed. In 2020, Washington is a net exporter of energy. As renewable generation fills the state's additional energy needs, Washington becomes a net importer, bringing in 43% of its electricity by 2050 in the Electrification Scenario, 36% of which comes from Montana and Wyoming wind. To understand where imports into Washington derive from throughout the West, please see page 39 of the technical report in Appendix B. The lower relative cost of these out-of-state resources versus in-state opportunities limits the growth of new renewable capacity in state until 2040 when Washington starts to build solar and offshore wind."
    Washington State Electric Utility Resource Planning 2020 Report Pursuant to RCW 19.280.060" – Washington State Department of Commerce, December 2020
    "Hydropower will remain the dominant source of electric for Washington utilities over the 10-year forecast period. Generation from coal-fired electricity will decrease in the forecast period that will increase reliance on natural gas-fired generation.
    Base-year aggregated state utility load has remained in a narrow band over the period from 2008 through 2020. Load growth forecasts by utilities for the five and 10-year out points have been trending down with each successive Commerce Utility Resource Plan report.
    The statewide aggregate growth in electricity demand is expected to be moderate, and most of this growth will be offset through energy conservation programs operated by utilities. However, several utilities with surplus generating capacity and very inexpensive electricity (Chelan, Douglas, and Grant PUDs) are forecasting very high load growth rates over the next 10 years.
    The report shows that short and long-term contracts make a smaller contribution to total resources in the base year (2019), but they are forecast to make larger contributions in the five and 10-year forecasts than was seen in the 2018 utility resource report.
    The Pacific Northwest Utilities Conference Committee 2020 Regional Forecast report reveals a projected electricity deficit for the Northwest starting in 2024 (283 aMW) and continuing to grow through the end of the 10-year planning period (3,200 aMW). PNUCC identifies a large number of planned resources in the region, but because they have less certainty from a financial or regulatory standpoint, they therefore are not included in the forecast.
    The region's premier planning body, the Northwest Power and Conservation Council, evaluated the adequacy of the Northwest electric power supply in 2020 and concluded that resources are not expected to meet its adequacy standard after 2020. Resources are considered adequate when the loss-of-load probability (LOLP) is less than 5 percent. However, with the planned retirements of Boardman and Centralia 1 at the end of 2020, the LOLP will reach of 7.5 percent in 2021 and will no longer meet the Power Council's adequacy standard. The retirement of the Hardin coal-fired power plant and the Klamath Hydro facility in 2021 were forecast to raise the LOLP to 8.2 percent by 2024. The Council noted that other power plant retirements announced for later in the decade would raise the LOLP value further if replacement resources are not brought online in a timely manner."
    Conclusion: *Individual utilities, especially those without wholly owned generation resources, are in a planning period of extreme uncertainty about the cost and reliability of their future power supply. Boards and staffs of these utilities need to continually educate themselves on the rapidly evolving scenarios and consider the implications for ongoing investments in their infrastructure.*
11. The plan should include a realistic worst-case analysis, to understand what could go wrong, and then plan for how to mitigate, properly fund, and implement, rather than revise the plan as needed - that won't work. Quote of note: *"The 2021 Northwest Power Plan includes many recommendations to the regional and to Bonneville. We recognize that the regional power system is in an extraordinary time of change with many uncertainties associated with future system operations."* (Page 6-42)

12. While the Council conducted various public meetings and workshops, there is a lack of transparency in the available reports on the models used, specific assumptions made, and datasets used to prepare the reports and conclusions. Various reports are given credibility and authority differently by different special interest groups.

Background: NW Regional Energy Challenges

Climate Disruption

- Texas and California rolling blackouts are harbingers of our climate disrupted future.
- Global carbon emissions have increased over 3X since 1960, spiking atmospheric CO2 to dangerous levels never seen in over 400,000 years of planetary history.
- As many as 1 million species are now at risk of extinction, many within decades.
- Oceans have been rapidly heating over the past few decades, with about half of the increase since 1865 occurring in the past 20 years.
- Globally, governments are accelerating their plans to reduce climate disruption through urgent moves to decarbonize the planet.

Northwest Regional Response: Rapid decarbonization, increased probability of rolling blackouts

While some of the material below highlights WA energy strategy, it is just a representative example of what the whole Northwest is grappling with as it moves to decarbonize. For example, Oregon is seriously considering initiating a 24/7/365 spill of hydro, which will reduce renewable hydro capacity that would otherwise be used to firm solar, wind and meet base load.

- To decarbonize the energy sector, Washington state just released their 2021 Energy Strategy, which calls for a rapid shift from fossil fuels to clean electricity, resulting in a near **doubling** of electric load by 2050 (see chart and discussion below). While the strategy relies on hydro to firm that vast new portfolio of intermittent and dispersed wind and solar energy, in a climate warmed world, hydro flows will likely become problematic, making this increasingly difficult, especially since no new hydro is planned.
- Washington is also rapidly shutting down all coal energy production (3,000 MW), increasing dependance on hydro but **reducing the headroom to meet regional load**, with **forecasts of imminent rolling blackouts** similar to what Texas and California are experiencing during extreme weather events.

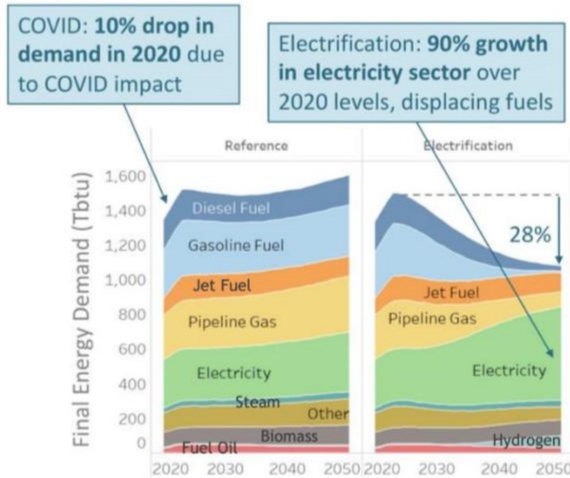
Washington State law declares that a successful energy strategy must balance three goals:

- **Maintain competitive energy prices that are fair and reasonable** for consumers and businesses and support our state's continued economic success;
- **Increase competitiveness by fostering a clean energy economy and jobs** through business and workforce development; and
- Meet the state's obligations to **reduce greenhouse gas emissions 45% below 1990 levels by 2030 and 95% below by 2050**.

We would add that a missing first bullet should strongly affirm maintaining reliability to avoid rolling blackouts.

Observations, Questions, and Implications

- **To achieve that 95% reduction of greenhouse gas emissions**, Washington energy strategy significantly reduces fossil fuel use and replaces it with clean renewables, firming with hydro and storage. The net result is Total Energy use will decrease by 28% (see chart at right), but electricity use will grow 90%. That electricity will primarily consist of hydro, wind, and solar plus storage. Washington is rapidly removing coal from the fuel mix, with natural gas to follow.



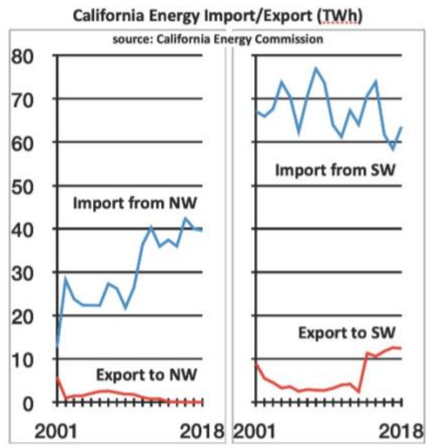
- **That near doubling of load comes primarily from the electrification of transportation and heating**. A whopping 45% of Washington greenhouse gas emissions come from transportation. Electric transportation and heating is much more efficient than fossil-fuel, leading to the 28% reduction of TOTAL energy.
- **Washington's strategy relies on current levels of hydro to firm a vast new portfolio of intermittent wind and solar energy**. But climate disruption is projected to eliminate much of the snowpack in the region, increase extreme rain events, increase spill and stress fish populations. All these things will introduce major variability in hydro flows. Hydro may be less firm, and potentially more intermittent than the past.
- **Washington plans to essentially require the development of a new renewable energy capacity that is twice the size of the Northwest dam system** (developed 100 years ago), in an era that has much more stringent environmental and permitting requirements. This is like a Manhattan project and an Apollo moon shot ongoing for the next 20 to 30 years.

There is no plan for how to do that while meeting their objectives of an equitable, inclusive, resilient clean energy economy. Several issues and challenges need to be clarified.

- **Land for Wind, Solar and Transmission** - We have seen estimates of over 1 million acres needed (see discussion and chart below). How much is needed and can permitting meet environmental requirements in a timely way? At what cost? How long will it take to acquire the land, build the transmission corridors and build the wind and solar capacity? At what cost? How will it impact the cost of electricity? Will Montana, Idaho and Wyoming want to build wind and solar and export it to Washington and Oregon, requiring over a million acres of their wild land? What are the impacts on the industry, BPA revenue/expense, firming of renewables, replacement of capacity, decarbonization legislation, siting, permitting? Using Benton County, WA as an example, Scout Clean Energy of Colorado recently submitted an application to develop a wind power facility in Benton County, Washington. Northwest power producers should provide power to the Northwest first, before exporting to other states such as California and Colorado.
- **Reform and Expand Wholesale Electricity Markets** - The Northwest is very vulnerable to Texas/California style energy disruption. It is the only major economic region of the US without a Regional Transmission Organization (RTO) to integrate and coordinate regional supply and demand (see chart below and discussion in *Background Material* section). It's notable that Texas and California RTOs are not regulated by FERC, leading to extreme "market pricing" fluctuations. To avoid Texas/California style blackouts and market price extremes, the Northwest should accelerate planning and deployment of new energy resources and establish a centralized Regional Transmission Organization (RTO) to ensure resource adequacy. An RTO provides better coordination for transmission planning, unit commitment (deciding which generators will be available to run) and transmission system use. **This RTO should be dedicated to providing power to the Northwest first, before exporting to other states such as California.** When RTOs are regulated by FERC, it ensures **fair and open access** to a broader footprint and **won't be**

controlled by a single party. RTOs are therefore more cost effective and efficient to integrate loads and resources versus alternatives.

The shift from concentrated to dispersed energy will require significant new transmissions network - As solar and wind are deployed at optimal sunny and windy locations, they will be more **dispersed** and **distant** than current base-load energy generation. To procure power from distant generators, a utility currently must separately arrange for transmission rights across each separate system used to transport power to its ultimate delivery point. The utility must pay the owner of each transmission system a fee to move power across its system. The massive new dispersed interstate solar/wind portfolio will require a much more efficient coordinated system.



California's thirst for Northwest energy - As the seminal book on California water politics, *Cadillac Desert*, points out, "*Water flows uphill towards money.*" The same can be said of California's notorious energy politics, as climate extremes may foster predatory pricing, reminiscent of California's water war and Enron scandals. **If it were its own nation, California would have the fifth largest economy in the world. California's $3.2 trillion economy depends on reliable energy, at almost any price**. As John Goodin, CAISO senior manager for infrastructure and regulatory policy, observed: "*You not only have to lock up the source, but you have to lock up the transmission as well... CAISO wants out-of-state suppliers to dedicate specific generation resources, including pooled resources, to serve California load so that CAISO is not relying on supply that doesn't materialize.*" As the chart at right shows, California imports increasing amounts of Northwest energy with little in return. Will Northwest energy developers commit to selling to the Northwest or be drawn to out of region sales (e.g. Shepherds Flat, representing more than 20% of Oregon's wind power generating capacity, sells their energy under 20-year contracts to Southern California Edison; Scout Clean Energy of Colorado has submitted an application for the energy from Washington's Horse Heaven Wind Farm.

BPA Plans - Everyone wants BPA to ensure power reliability, but they have no mandate and no desire to be an RTO. In our view, BPA could be a major part of a FERC mandated RTO and stakeholder coalition. BPA does NOT have any requirement (or funding or plans) to build more generating capacity or new transmission lines. BPA is obligated to only provide preference customers with their TIER 1 allocation of the Federal hydro system (minimum low water year) and nothing more. Further, BPA is looking to "maximize the value" of all excess power above TIER 1 load by selling it on the open market (Tier 2) to the highest bidder, potentially leading to Texas/California style extreme pricing. **Market rates can only go up** due to supply dropping (coal plants closing) and demand doubling (electrification of heating/transportation). BPA gets all the secondary market revenue (above TIER 1), utilities take all the market/financial risk, even if BPA buys the power on their behalf. Further more, who knows what's going to happen with the BPA contract, to be negotiated in 2028.

Are there ways for the region to coordinate with BPA and their Federal command to support the decarbonization effort?

n short, this is a complex massive project, with a lot of moving parts. Washington has released its ambitious *2021 nergy Strategy* and *Clean Energy Transformation Act* for getting to zero carbon. What we have outlined above is qually applicable to other Northwest states - Oregon, ID, WY, etc..

ackground: Key Elements of a Successful Solution

o decarbonize the planet, nations are essentially trying to replace a fossil fuel infrastructure, developed over the ast 100 years, with clean renewable energy, in less than 30 years. This is a very complex, very expensive task, with lot of moving parts, and problems that have no easy solutions.

ach nation and each state is endeavoring to do an Apollo moonshot and a Manhattan project, over and over and ver again, until the work is done. One cooperative utility board member likened it to" rebuilding a DC-3 into a 787 reamliner, while in flight, without losing altitude or direction, and keeping the passengers safe and comfortable t the same time."

Developing a massive new portfolio of regionally dispersed generation resources, routed to Northwest population centers, which are expected to double electric energy demand by 2050, will require a wealth of solutions to meet the challenges discussed above.

While much attention has been focused on new renewable technologies like solar and wind power, at the end of the day, massive amounts of land, transmission and permitting, will be the glue that binds it all together. Things like acquiring over a million+ acres of land to host new solar and wind projects. Building over a thousand miles of new transmission lines to move that new dispersed energy to population centers. That network of generation and transmission will need 21st century coordinating entities to ensure **reliable power**, even when the wind and sun are taking a break. And that power needs to be **delivered at a fair and affordable price**.

Regional Transmission Organization (RTO) Dedicated to the Pacific Northwest

The primary function of this RTO is to **ensure reliability** by integrating a diverse mix of power resources on to the electric grid, for the Pacific Northwest, matching power generation instantaneously with demand to keep the lights on. Harnessing a commodity and then moving it at the speed of light across thousands of miles of high-voltage wires involves sophisticated coordination among **utilities**, **energy generators** and other **resource suppliers**, as well as **consumers**. The ultimate goal is to ensure Northwest access to **affordable**, **reliable** and **sustainable power** – made possible through efficient administration of independent and transparent wholesale energy markets.

This RTO needs to be mandated to solve reliability issues in the Pacific Northwest first. We support for it to be overseen by the Federal Energy Regulatory Commission (FERC), which grants the authority to develop needed new energy resources and regulates the transmission and wholesale sales of electricity in interstate commerce.

This RTO should be created by regional stakeholders in response to FERC's Orders 2000 and 888, to:

- Prioritize power for the Pacific Northwest first, before selling out of state
- Facilitate competition among wholesale suppliers
- Provide non-discriminatory access to transmission by scheduling and monitoring the use of transmission
- Perform planning and operations of the grid to ensure reliability
- Manage the interconnection of new resources, e.g., generation, loads...
- Oversee competitive energy markets to guard against market power and manipulation
- Provide greater transparency of transactions on the system

Stakeholders in this RTO should include FERC, the western EIM, state PUCs, BPA (substantial transmission and generation resources), new solar and wind generators, utilities – a coalition of the willing – built upon successful existing RTO models such as the Southwest Power Pool (SPP). We should avoid unregulated (no FERC oversight) models such as those employed by Electric Reliability Council of Texas (ERCOT).

Form a Strategic Working Group Dedicated to Establishing an RTO

There is a burning need for regional collaboration and coordination with each other and the Federal Government.

We foresee the potential of a powerful collaboration between the State and Federal government, Department of Energy, state Departments of Commerce, BPA, the western EIM, electric utilities, environmental stewards, and developers of energy solutions, driving policy, funding, and solutions, grounded in a clear-eyed understanding of the challenges and solutions before us.

> *"The engineering of decarbonized systems may prove relatively easy once enough companies, governments, and consumers focus on the need."*
> David Victor author of Global Warming Gridlock

We believe a comprehensive approach to working with stakeholders and thought leaders in DOE and Commerce to problem solve, plan and fund the transition, including establishing an RTO dedicated to the Pacific Northwest, and deepening understanding of options, pros and cons. Below, we highlight first steps and potential solutions to the climate actions and challenges discussed above.

This effort will require trillions of dollars. We need to be looking at a national funding effort. Governors, utilities, and other stakeholders need to identify applicable Federal, state and local funds (e.g. We have found the DOE and Pacific Northwest National Labs to be excellent engaged funding partners with access to funds and best practices). We feel that we can work that network to build a coalition of stakeholders and thought leaders to identify and take on the big challenges, and fund solutions that can serve our region and the nation.

Key challenges include:

- Forming a nonpolitical RTO dedicated to the Pacific Northwest, with leadership rooted in utility stakeholders
- Begin EIM membership discussions to support a broader RTO formation plan
- Investigate emerging firming solutions that may reduce the scale of renewables required
- Assess, plan, permit, and build a feasible transmission network
- Develop Federal, state and local funding support (e.g. from DOE, DOC, PNNL, Amazon's Earth Fund, etc.).
- Streamline public policy and rules related to deployment of generation and transmission systems

Example Opportunities from the Washington 2021 Energy Strategy

WA's *2021 Energy Strategy* includes the following action items that may have funding available:

- Request support from the U.S. Department of Energy and Pacific Northwest National Laboratory to convene a distributed energy resource workgroup to identify and resolve grid architecture barriers to DER deployment.
- **Electric utilities should pursue the long-term development of a fully integrated western regional electricity market** (see RTO discussion above), beginning with expansion of organized markets to trade day-ahead and longer-term resources. Long-term market development should explore opportunities to trade capacity resources including demand response resources.
- Wholesale market participants should develop market rules to allow trade in electricity from sources verified to comply with CETA's clean energy requirements. The UTC and Commerce, with input from the Carbon and Electricity Markets Workgroup, should adopt rules to ensure this outcome.
- Commerce's 2024 CETA evaluation under RCW 19.405.080 should include an assessment of industry progress in developing efficient and resource-specified electricity markets.
- Funding should be made available to Commerce and electric utilities to conduct a statewide clean energy potential assessment to identify clean energy development zones
- The Governor's office, the UTC and Commerce should pursue opportunities for enhanced transmission planning and integration across the Western grid and advocate for joint development where feasible.
- Utilities and planning agencies should evaluate the need for joint development of new and upgraded transmission capacity and consider the viability of a regional transmission organization.
- Commerce and the UTC should review the progress and outcomes of the NWPP RA initiative and evaluate the need for additional state action to ensure CETA's RA requirements are fulfilled.
- Provide support for increased deployment of advanced metering infrastructure (AMI), with safeguards for privacy and security.
- Provide state support for flexible and resilient planning and project development by creating a new cluster within Commerce's Office of Economic Development and Competitiveness to focus on utility grid optimization and DER deployment.
- Target CEF funding to projects that enable flexible load management and increase grid resilience.
- Develop resources for expanded outreach, technical assistance and education for community efforts.
- Create specific programs for Tribal energy projects that promote Tribal sovereignty and self- determination.
- Support the development of community resilience hubs and energy districts.
- Support clean energy projects that benefit agricultural communities.

BPA

PNGC had a wide-ranging discussion with BPA Administrator John Hairston on the future of BPA, developing a regional RTO, resource adequacy and CAISO. Administrator Hairston was clear that BPA would limit BPA's support of an RTO to providing technical counsel. He made it clear that BPA would continue to provide an unspecified portion of their capacity to Tier 1 Preferred Customers but would also provide market-priced firm clean hydro energy products to customers such as CAISO.

PNGC will continue to deepen this conversation as we prepare for 2028 contract negotiations.

Background: Washington 2021 Energy Strategy

Washington's *2021 Energy Strategy* is a bold aspirational document aimed at building an **equitable**, **inclusive**, **resilient clean energy economy**. Similar to Washington's *Clean Energy Transformation Act* (CETA), it lacks critical implementation detail and funding specifics.

The strategy document deepens our understanding that enormous change is upon us. And its planning gaps, once understood by our legislators, may lead to a deep appreciation of the utility industries energy, capital planning, implementation, and engineering prowess.

What the Washington *2021 Energy Strategy* is and is not

It's important to keep in mind that the Strategy is the first stake in the ground - leading with very high level goals and strategic direction. It is very light on specifics. The most glaring example is the section on developing new energy resources – *Accelerate Investment in Renewable Generating Resources and Transmission. It*'s just four pages long. The section's topics include a few paragraphs each on:

- Assess the Potential for and Facilitate Deployment of New Clean Energy Resources
- Strengthen the Transmission System across the West and within the State
- Encourage and Monitor Development of a Resource Adequacy Program
- Reform and Expand Wholesale Electricity Markets

Washington *2021 Energy Strategy* Aspirational Goals: A Holy Grail

Washington State law declares that a successful energy strategy must balance three goals:

- **Maintain competitive energy prices that are fair and reasonable** for consumers and businesses and support our state's continued economic success;
- **Increase competitiveness by fostering a clean energy economy and jobs** through business and workforce development; and
- **Meet the state's obligations to reduce greenhouse gas emissions** 45% below 1990 levels by 2030 and 95% below by 2050.

What will the Washington *2021 Energy Strategy* cost?

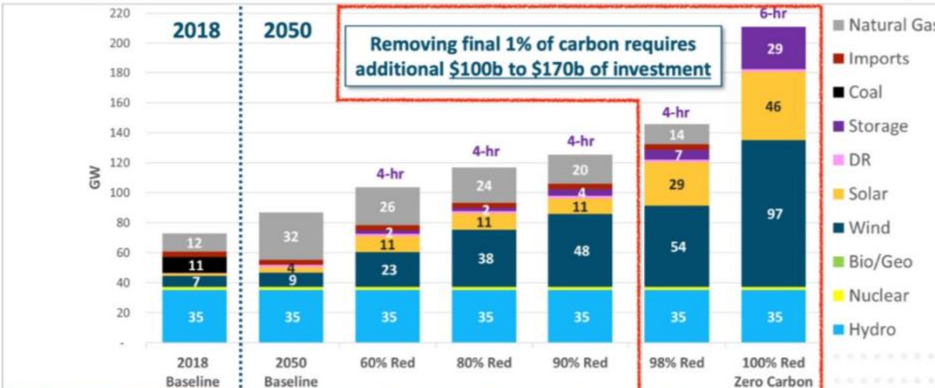
Washington evaluated a number of scenarios, and the "electrification" approach was found to be the lowest cost. While they are vague about the details, it appears that annual net energy costs would increase by about 1% of GDP by 2030 – about $6 billion per year – equivalent to an 11% increase in Washington's annual budget of $57 billion. There is no indication of where this funding will come from - rate payers, taxes, bonds, investors, grants, carbon tax?

Will a wild west of energy investors develop these resources and force Washington citizens to pay "market rates" to meet demand for energy, similar to what we have seen playing out in Texas, where the consumer becomes subject to predatory pricing during cold snaps and heat waves? We think a Northwest RTO will prevent that from happening.

E3 Resource Adequacy Study offers some preliminary estimates on the scale of the problem

E3's 2019 study *Resource Adequacy in the Pacific Northwest - Serving Load Reliably under a Changing Resource Mix* provides a framework to think about the Washington Energy Strategy if its load doubling zero carbon approach were mapped to the entire Northwest region.

Referring to the chart below, on the left side we see the 2018 baseline generation resource mix capacity for the Northwest region, with hydro, coal, and natural gas making up the bulk of generation. Total capacity is about 75 GW, serving a nominal regional load of 247 TWh/year, with peak load of 43 GW. The load in 2050 was estimated by E3 to increase to 309 TWh/year and peak load of 54 GW.



	2050 Baseline	60% Red	80% Red	90% Red	98% Red	100% Red Zero Carbon
Carbon (MMT CO2)	50	25	12	6	1	-
CPS (%)[1]	63%	86%	100%	108%	117%	123%
GHG Free Generation (%)[2]	60%	80%	90%	95%	99%	100%
Annual Renewable Curtailment (%)	Low	Low	4%	10%	21%	47%
Annual Cost Delta ($B)	Base	$0 - $2	$1 - $4	$2 - $5	$3 - $9	$16 - $28
Additional Cost ($/MWh)	Base	$0 - $7	$3 - $14	$5 - $18	$10 - $28	$52 - $89
% GHG Reduction from 1990 level	16%	60%	80%	90%	98%	100%
Gas Capacity Factor (%)	46%	27%	16%	9%	3%	0%

[1]CPS+ % = renewable/hydro/nuclear generation divided by retail electricity sales
[2]GHG-Free Generation % = renewable/hydro/nuclear generation, minus exports, divided by total wholesale load

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Now let's focus on the right side of the chart in the red outline. the right most stacked column is similar to Washington's 100% reduction of greenhouse gas emissions (GHG , zero carbon), but the E3 model is for a 25% increase in load. Washington is projecting a 90% increase in load, which would scale the 208 GW total to 501 GW of needed capacity.

Either way, to get to zero carbon requires a tremendous amount of solar/wind power over-build, and hence curtailment, to handle the low capacity factor of solar and wind in the Northwest region, especially when the sun isn't shining and the wind isn't blowing. But if the state were to ease that emissions requirement by just 2%, it allows a significant reduction of cost. The 98% GHG reduction stacked column, just left of the right one, shows total capacity dropping from 208 GW total to about 145 GW in the E3 model. The reduction in renewables and storage would be filled by natural gas generation, used only as a last resort. For the Washington model, where load nearly doubles, the 98% GHG reduction would reduce the requirement from 501 GW to 303 GW.

Utility Dive has more on the E3 study and strategic use of modest amounts of natural gas generation to reign in exponential renewables costs:

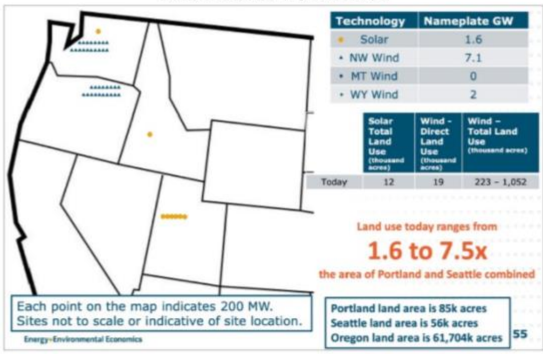
> The E3 study found that without at least some new natural gas plants to run at peak times, the costs of cutting emissions across the Northwest increase dramatically. Reducing emissions by 90% by 2050 — which retains less than 20 GW of natural gas capacity in the regional portfolio — would cost around $5 billion, but a 100% reduction by 2050, with no natural gas, would cost nearly $30 billion - a sixfold increase in cost. That study was commissioned by several utilities in the region such as Puget Sound Energy and Avista and is one of the primary pieces of research guiding utilities and regional agencies as they work to avoid resource constraints and blackouts, as recently happened in California.
>
> The cost spikes, because natural gas plants are the cheapest form of last-in-line defense against power shortages on peak days with low renewable production. The natural gas plants used in projected scenarios are only run 3% of their time, but that small contribution makes a big difference to the bottom-line costs, according to the study. While the rich hydropower base is a "massive advantage" for the Pacific Northwest that allows it to require less natural gas backup for renewables than other regions, Olson said, hydro is not the be-all-end-all, especially given that hydro production can be variable from year to year.
>
> Reaching 100% reduction in greenhouse gases by 2050 would require a colossal amount of new renewable energy projects — 97 GW of wind power, which is nearly as much as all current wind capacity across the entire U.S., and over 45 GW of solar power. "*You run out of the ability of the system to absorb renewable energy,*" Olson said, even with large buildouts of lithium-ion battery storage. The study assumed storage durations of up to 4 to 6 hours, so the ongoing search for a "holy grail" of long duration storage over 24 hours could change the picture.

Enormous Land Requirements

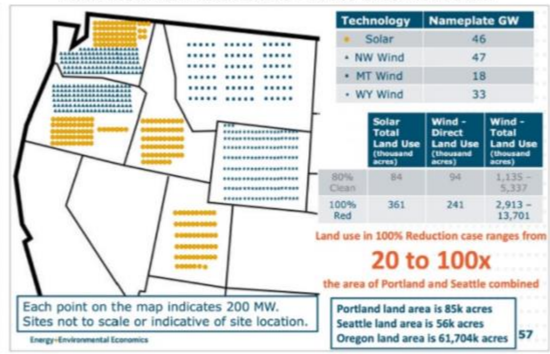
Details In the Washington energy strategy are vague regarding land and permitting costs assumptions for solar, wind and transmission deployment.

Land is a sleeper issue in transforming the grid. From a national perspective, it has been estimated that we need to build three 1,000-mile-long transmission lines every year for the next 30 years to interconnect distributed solar and wind generation with the grid. And in the past 10 years we haven't built even one. It's going to be a big expensive job.

2018 Installed Renewables



2050 Installed Renewables - 100% GHG Reduction



Referring to the chart above, to maintain resource adequacy and prevent rolling blackouts similar to what we have seen in Texas and California, E3 , in their 25% load increase model above, estimates 97 GW of new wind and 46 GW of new solar are needed, requiring an estimated **3 to 14 million acres of land** – or **20 to 100 times the land area of Portland and Seattle combined**. It is unclear whether there are enough sites that are suitable, purchasable and permittable for that level of renewable energy deployment. And that's just for a 25% load increase by 2050, not the 90% Washington energy strategy estimate.

And depending on how thorough we want to be reducing fossil fuel use, Pacific Northwest National Labs estimates to replace jet fuel at SeaTac would require 36% of the electricity generated in Washington, equivalent to 5,000 new wind turbines.

Enormous Transmission System Requirements

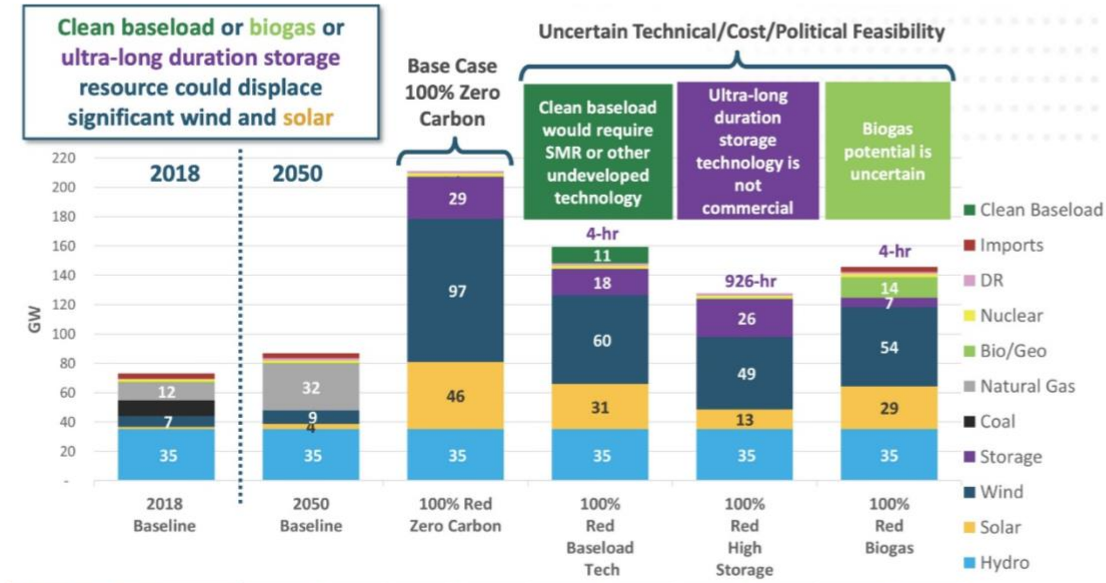
And once you build all that new solar and wind generation on millions of acres of western land, how do you get it to where it will be used?

Most of the best wind and solar sites are located either in Montana or Wyoming (for wind) or Southern Idaho and Utah (for solar). Delivering energy from 140+ GW of wind and solar into load centers would require dozens of new high voltage transmission lines. Will states be willing and able to purchase and permit the required land and then sell the energy to Washington, rather than use it themselves? In effect they are impacting their natural lands for Washington energy benefit. And what happens when carbon taxes force western states that embrace coal to adopt CETA-like policies that shift from thermal to wind and solar resources? Why transmit it to WA when they will need it for their own economy?

The Northwest faces this same issue when it comes to exporting our precious hydro energy to California to meet their hunger for firm energy to stabilize their growing solar portfolio. Should we be exporting Northwest hydro that could be used locally to serve base-load and firm our new portfolio of intermittent wind and solar resources?

Thinking Outside the Box

Referring to the chart below, E3 explores "uncertain technical/cost/political feasibility" solutions that could significantly reduce costs of 100% GHG reduction implementation. The three solution areas are, from left to right, SMR or similar firm base load generation resource, ultra-long duration storage such as compressed green hydrogen powered fuel cells, and biogas. Or, how about natural gas with 100% carbon capture. All of these things are being investigated and R&D funded by DOE with potential solutions emerging in the 2050 planning horizon of the Washington energy strategy. **We may be able to avoid massive overbuild of solar and wind if emerging technologies can provide clean alternatives to natural gas peaker plants**. We could start planning for a "no regrets" solar and wind generation capacity, and by the time that is complete, we may have clarity on if there are lower cost options for peaking.



Carbon (MMT CO2)	50	0	0	0	0
Annual Cost Delta ($B)	Base	$16- $28	$14-$21	$550-$990	$4 - $9
Additional Cost ($/MWh)	Base	$52-$89	$46-$69	$1,800-$3,200	$14 - $30

Energy+Environmental Economics

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Background: Imagine the Unimaginable: How the Pacific Northwest is trying to build a reliable grid in a changing climate

Reporter Kavya Balaraman did a deep dive into the western regions challenges as we attempt to rapidly buildout new solar, wind, storage and transmission systems, in the midst of extraordinary climate disruptive heat waves, cold snaps, fires and more. Key takeaways:

- This past summer, the Pacific Northwest experienced a heat wave that served as something of a wake-up call for the utility sector. The region experienced record-breaking temperatures in July — Portland, for instance, touched 116 degrees and broke records three days in a row — leaving utilities racing to prepare their infrastructure and urge customers to save energy.
- The heat wave this summer was "definitely a wake-up call about how high the summertime demand can get," Arne Olson, senior partner with Energy and Environmental Economics.
- Experts are concerned that things could have been a lot worse had conditions in the rest of the Western U.S. been different at the time — a sign, they say, that policymakers need to take a closer look at how extreme temperatures can affect grid reliability.
- "*Had we had a situation during the heat wave in the Northwest where California was also at peak usage, we may have had some issues, certainly,*" "*We may have run into a lack of capacity to be able to meet the load needs.*" Frank Afranji, president of the Northwest Power Pool (NWPP). ""
- "*We have to begin moving beyond historical evidence to understand how load reacts when temperatures reach such extremes.*" "*I think what the last year has taught us — from Oregon all the way to the experiences in Texas, really — [is] to try to imagine the unimaginable, if you will. We have to begin moving beyond historical evidence to understand how load reacts when temperatures reach such extremes.*" Megan Decker, *Chair, Oregon Public Utility Commission*
- On the supply front, the key concern for the Northwest is "water, water, water," said Ben Kujala, director of power planning at the Northwest Power and Conservation Council. He continues: "*Hydropower generation meets anywhere from half to 90% of the electricity demand in the footprint the council analyzes, so reliability is always a function of a particular year's precipitation and snowpack. With warmer winters, it's possible that the area will see more water in the system in the winter, meaning there will be less water left in the summer. There [are] some definite seasonal challenges that come from climate change — or it aggravates existing seasonal challenges that we already have.*" Dan continues: "*The growing number of electric vehicles on the road, as well*

as efforts to electrify the built environment, add another layer of complexity to demand forecasting, making it "one of the most difficult times right now to be planning."

- Navigating the regulatory process to approve renewable and transmission projects, takes into account reliability as well as the cost to customers, complicated by the local approval and construction process. *"Any time the utility builds a new wind farm or transmission addition, it needs to go through a local land use approval process, which could involve dealing with the federal government, state approvals, Native American tribes that have property ownership, and private owners." "So that ends up being a fairly detailed process that typically takes some years to bring a proposed project to actual construction. And then, of course, there [are] the challenges with the actual construction of any facility — the securing materials and personnel to actually do the construction."* David Eskelsen PacifiCorp

Learn More

Draft 2021 Northwest Power Plan

Pacific Northwest poised to test 100% renewables as utilities weigh gas vs. storage

Wind Power Project Rejection Database

Imagine the unimaginable': How the Pacific Northwest is trying to build a reliable grid in a changing climate

"The 2021 Northwest Power Plan For A Secure & Affordable Energy Future, Draft Plan, Council Document 2021-5, September 2021" – Northwest Power and Conservation Council

"Northwest Regional Forecast of Power Loads and Resources, 2021 through 2031" – PNUCC April 2021

"Washington State Electric Utility Resource Planning 2020 Report Pursuant to RCW 19.280.060" – Washington State Department of Commerce, December 2020

"2021 Energy Strategy Transitioning to an Equitable Clean Energy Future" – Washington State Department of Commerce, Second Draft, February 2021

"2021 PSE Integrated Resource Plan" – Puget Sound Energy, Final, April 2021

"2021 Clean Energy Implementation Plan" – Avista, October 2021

"Benton PUD 2020 Integrated Resource Plan" – Public Utility District No. 1 of Benton County, August 2020

"Here's a List of 317 Wind Energy Rejections the Sierra Club Doesn't Want You To See" - Robert Bryce

"Resource Adequacy Today and In the Future in California and the Pacific Northwest" – Energy+Environmental Economics, June 2019

"NWPP Resource Adequacy Program – Detailed Design" – Northwest Power Pool, July 2021

COVID-19 Update

San Juan County has experienced a resurgence of cases due to the delta variant and recommends masking in public indoor places. Please note that OPALCO offices remain closed to the public and its members. Staff has reinstituted remote work to ensure redundancy in the workforce.

For current information from San Juan County Health please use the link below:

https://www.sanjuanco.com/1668/2019-Novel-Coronavirus

OPALCO COVID-19 Update (Figures are reported from March 20th, 2020 to the date of transmittal, unless otherwise stated)..

COVID Assistance

Board Approved Funding includes all funding allocated for 2020 and 2021

	# of Accounts	Amount ($)	Board Approved Funding ($)	Remaining Budget ($)
Energy Assist (EAP-C) Commercial COVID	118	148,545	200,000	51,455
Energy Assist (EAP) Residential COVID	95	44,209	100,000	55,791
Extend Project PAL Benefits - COVID	222	27,200	70,000	42,800
Grand Total	405	219,954	370,000	150,046

Fee Assistance (Lost Revenue)

(Based on variance from collections comparing 2019 to 2020 for the period April 1st to Date)

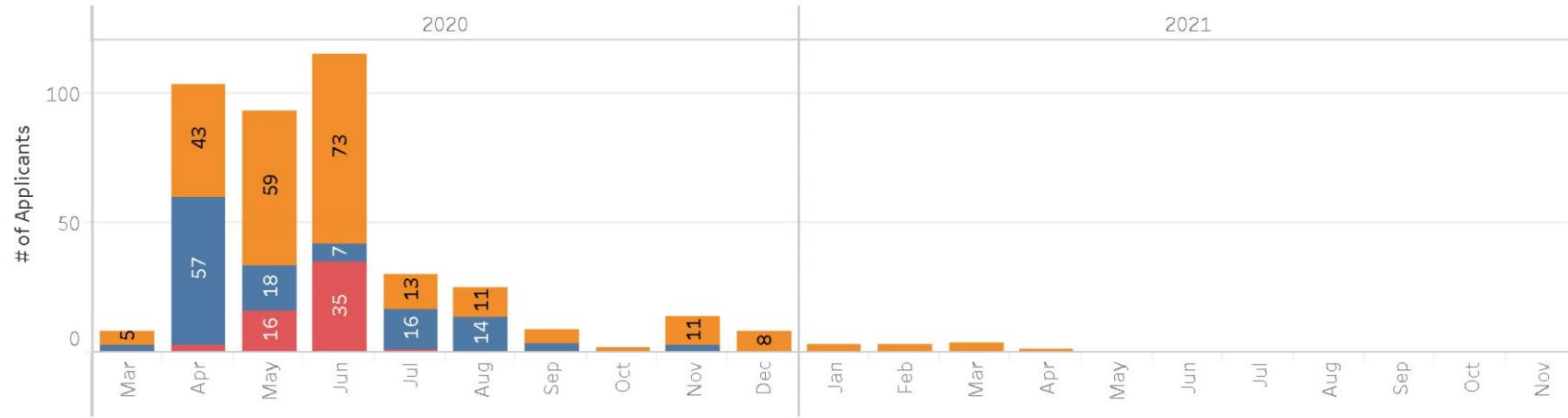
Penalties	95,493
Reconnection Fees	6,932

Measures	**Benefit**
Energy Assist (EAP-C) Commercial COVID	$67.57 per mo., based on number of number of meters on a commercial rate
Energy Assist (EAP) Residential COVID	Assistance ranges from $31.41 to $61.41, based on number of permanent household occupants
Extend Project PAL Benefits COVID	$100
Penalties	Waiving of late penalties (Normal penalties are 5% of the total balcance post-due date)
Reconnection Fees	Waiving of reconnect fees (Normal reconnect fee is $50 per instance of reconnecting after a discconnect for non-payment)

Member Donations to COVID-19 Relief Efforts

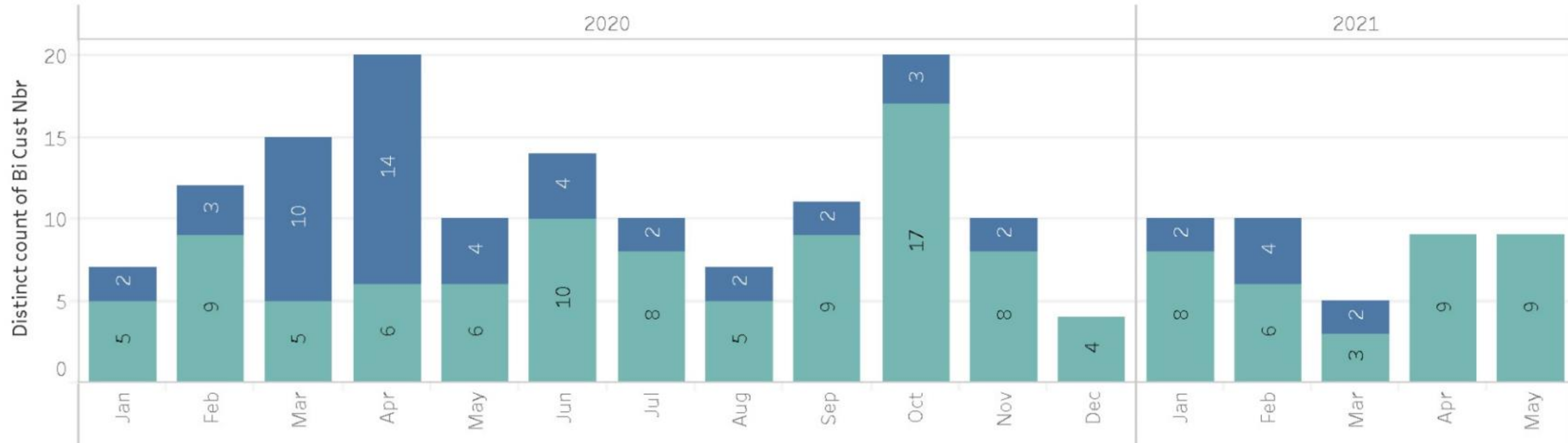
Staff will continue to communicate with members regarding the COVID-19 relief measures, including a request for donations. Staff continues to encourage members to donate to our PAL program.

COVID-19 Assistance Applications

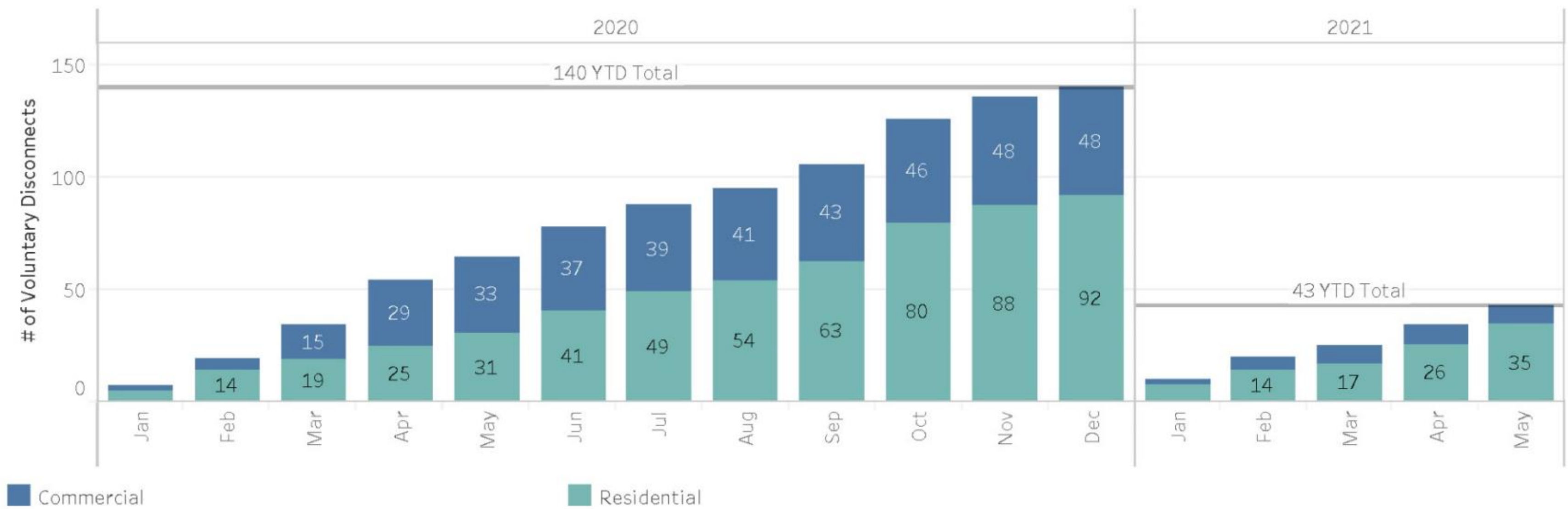


COVID-19 Assistance Applications Cumulative

Voluntary Disconnects (Meters)



Voluntary Disconnects Cummulative (Meters)



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A/R 30-60-90

- 30-day A/R is trending slightly higher.
- 60-day A/R is notably higher and stabilizing.
- 90-day A/R notably higher and stabilizing.
- We are seeing a flow through into the 90-day with a notable uptick on the 90-day accounts receivable. The lower usage profiles of the summer will aid in moderating this yet will become dramatic in the late fall. At this stage staff feels this is manageable through the summer and will revisit at the Q3.

Long Term AR Comparisons - 30/60 Day

	30 Day			30 Day % Difference			60 Day			60 Day % Difference		
	2019	2020	2021	2019	2020	2021	2019	2020	2021	2019	2020	2021
Jan	111,730	85,379	127,074		-23.58%	48.84%	3,837	3,101	55,338		-19.18%	1,684.60%
Feb	133,447	105,886	170,874		-20.65%	61.37%	4,511	4,333	57,736		-3.93%	1,232.33%
Mar	121,185	135,225	153,276		11.59%	13.35%	4,962	9,976	54,542		101.04%	446.76%
Apr	134,240	185,370	150,556		38.09%	-18.78%	5,479	41,845	58,142		663.72%	38.95%
May	88,272	134,798	115,334		52.71%	-14.44%	10,457	64,616	54,541		517.89%	-15.59%
Jun	80,172	103,575	92,861		29.19%	-10.34%	7,126	57,091	43,314		701.17%	-24.13%
Jul	62,481	97,956	91,044		56.78%	-7.06%	4,004	44,576	44,053		1,013.19%	-1.17%
Aug	54,195	107,577	76,503		98.50%	-28.89%	2,543	39,191	34,029		1,441.27%	-13.17%
Sep	62,931	96,832	93,309		53.87%	-3.64%	3,010	42,513	31,302		1,312.28%	-26.37%
Oct	48,634	102,980	72,120		111.75%	-29.97%	2,725	32,868	15,118		1,106.30%	-54.00%
Nov	75,636	106,860			41.28%		2,078	31,986			1,439.43%	
Dec	95,454	142,795			49.60%		3,218	42,154			1,209.94%	

Long Term AR Comparisons - 90 Day

	90 Day			90 Day % Difference		
	2019	2020	2021	2019	2020	2021
Jan	16,248	14,427	87,419		-11.21%	505.95%
Feb	16,995	12,166	110,764		-28.42%	810.45%
Mar	16,257	7,762	104,089		-52.25%	1,241.04%
Apr	17,451	10,546	110,135		-39.57%	944.38%
May	20,553	25,016	109,719		21.72%	338.59%
Jun	19,925	51,746	125,665		159.70%	142.85%
Jul	21,349	65,931	133,418		208.82%	102.36%
Aug	20,486	66,002	130,850		222.19%	98.25%
Sep	19,305	72,854	122,901		277.39%	68.69%
Oct	15,115	71,660	80,702		374.08%	12.62%
Nov	15,429	75,673			390.47%	
Dec	13,614	77,291			467.75%	

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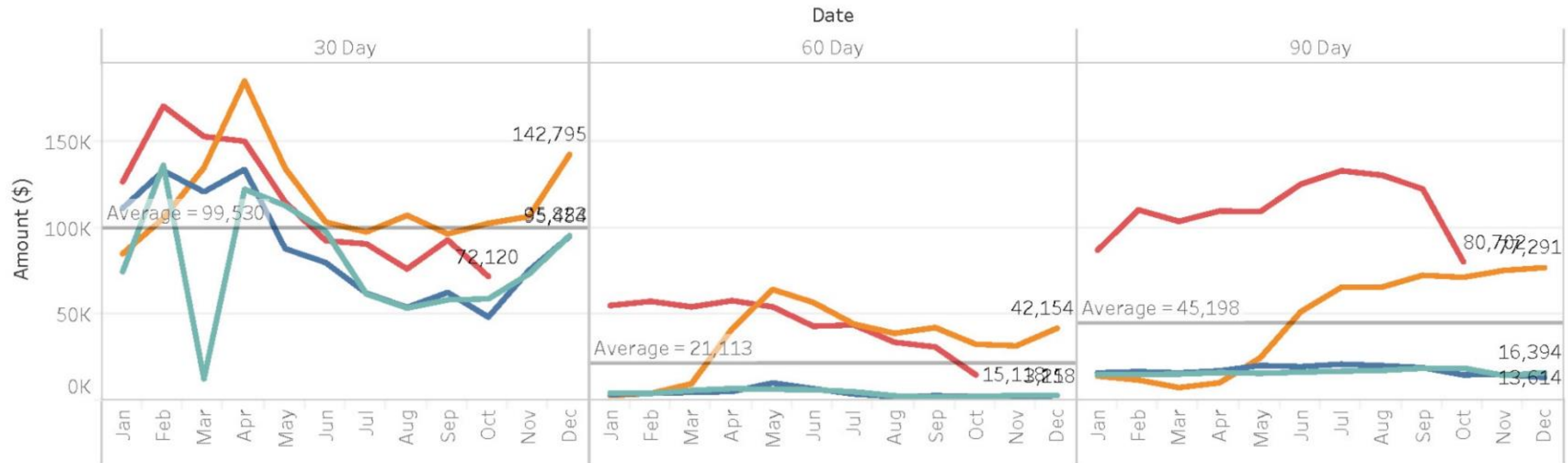
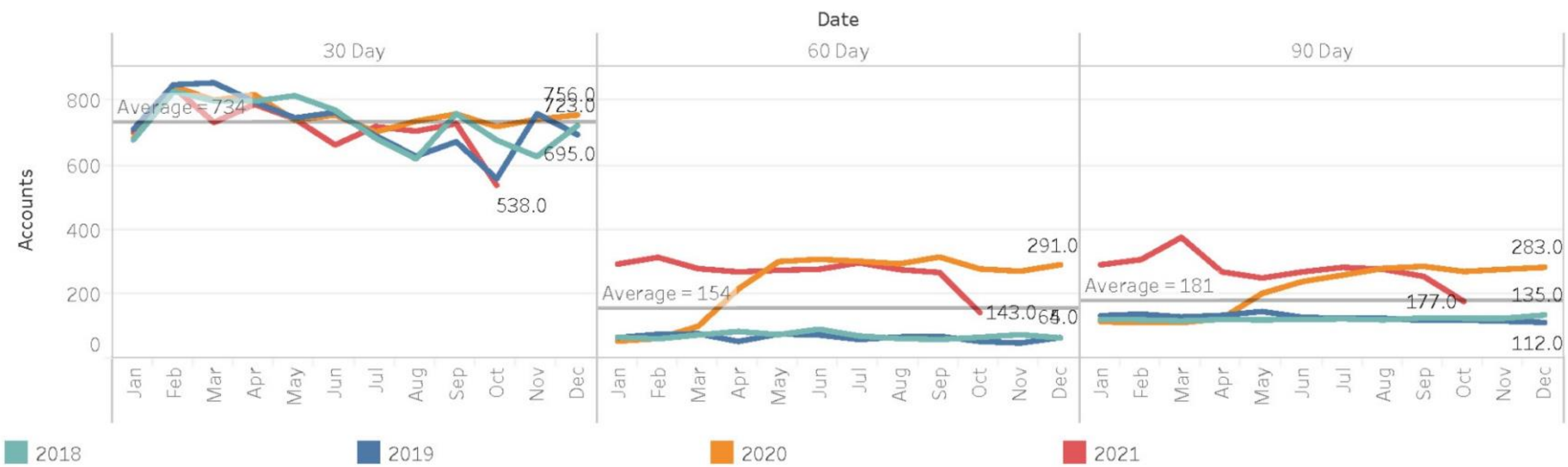
Long Term AR ($)

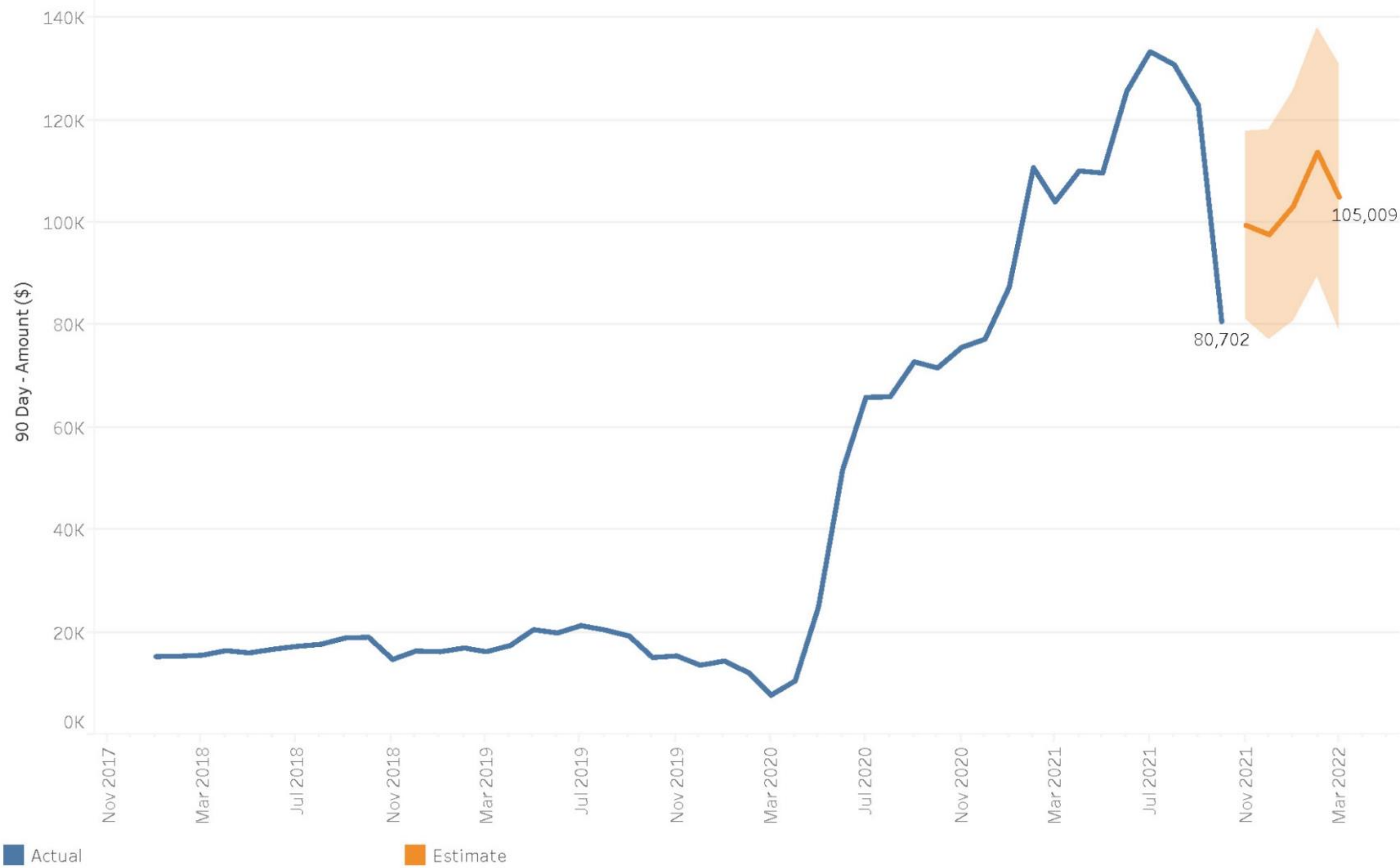


Long Term AR (Count)



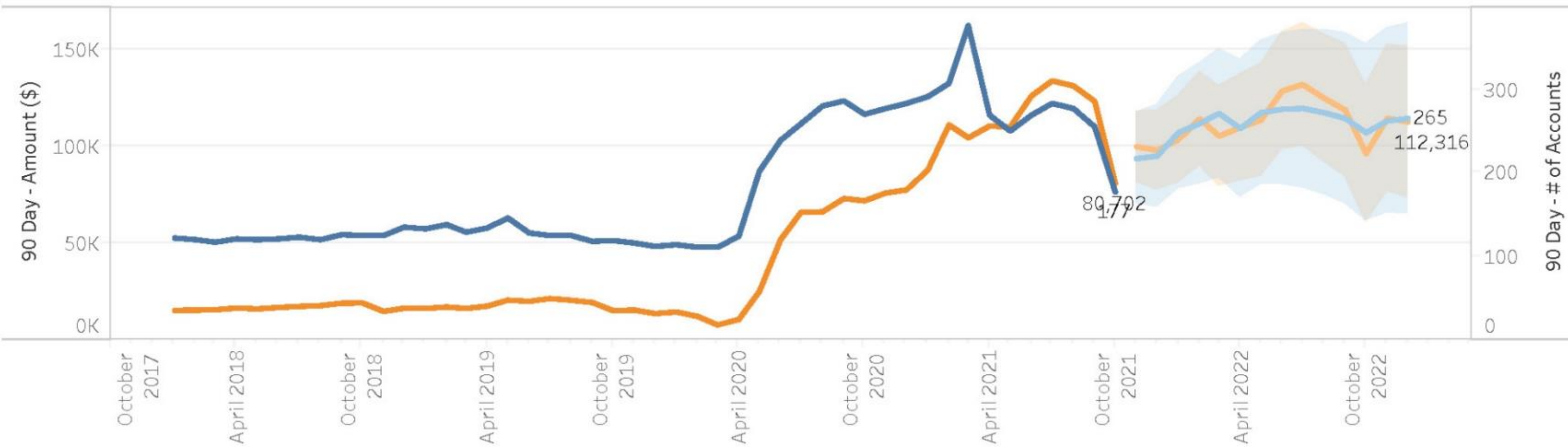
AR - 90 Day with 5 month Forecast ($)

The forecast (seen in the light blue with a shaded prediction confidence bands) ratched down due to the plateau.

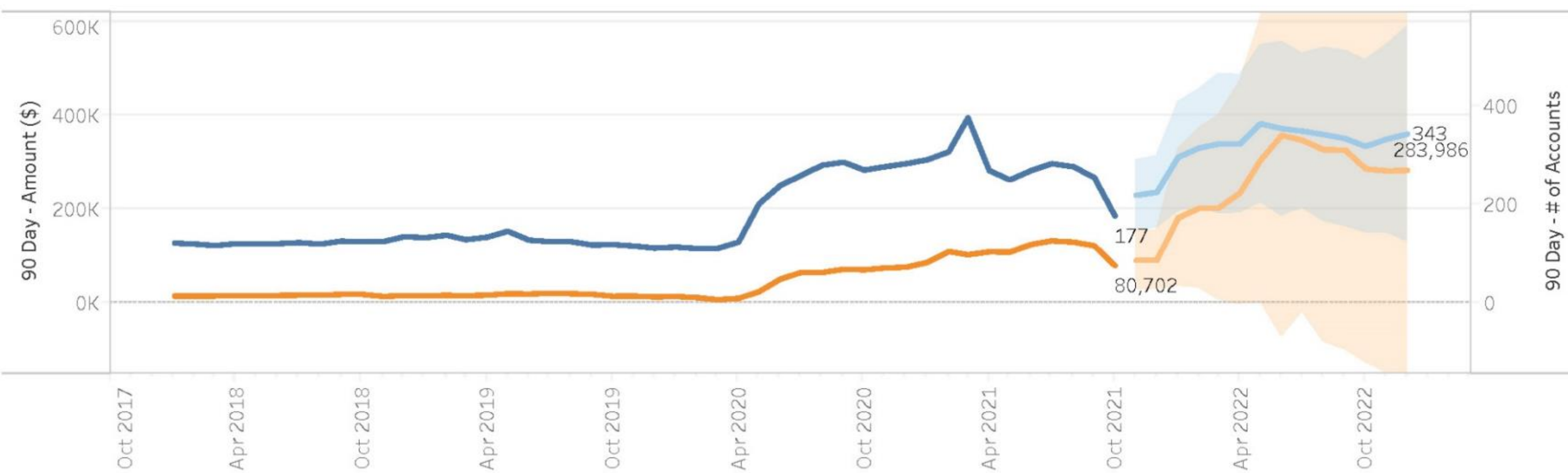


AR - 90+ Day with YE2021 Forecast ($) - Assumed

The forecast (seen in the light blue with a shaded prediction confidence bands) ratched down due to the plateau.



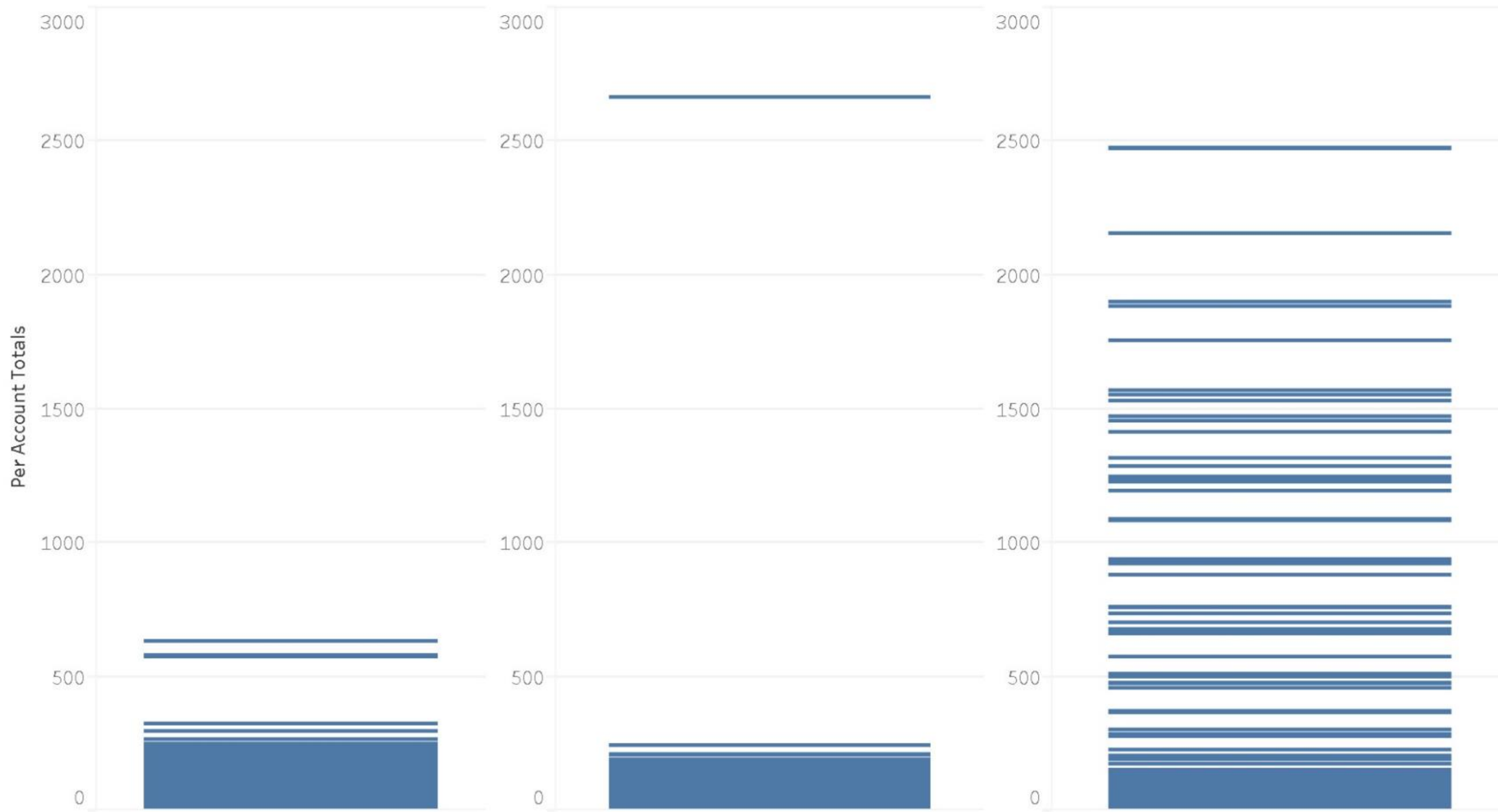
AR - 90+ Day with YE2021 Forecast ($) - High



30/60/90 Day AR Per Account Totals

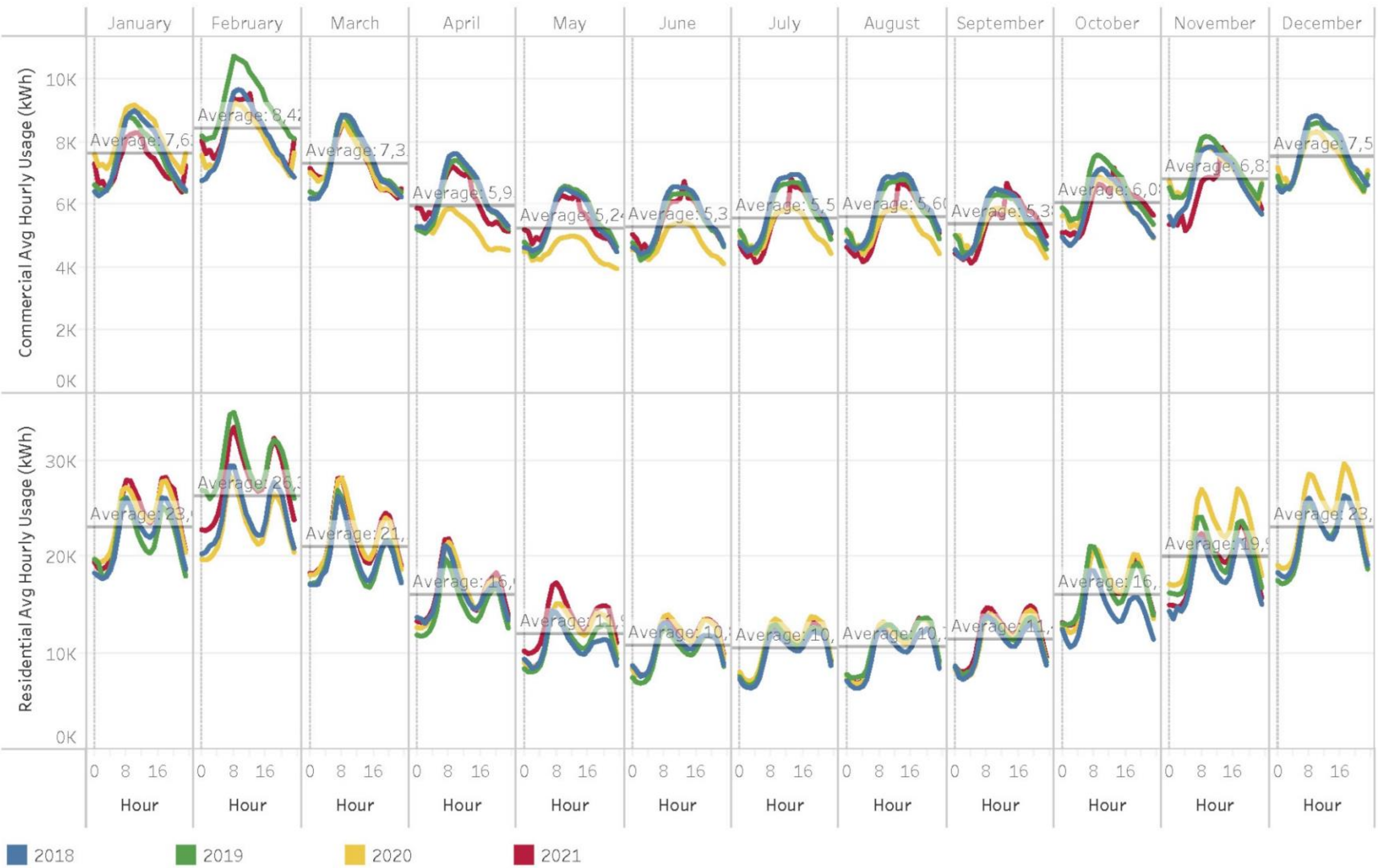
30 Day - # of Accounts	60 Day - # of Accounts	90 Day - # of Accounts
282	100	142

30 Day - per Account Totals | 60 Day - per Account Totals | 90 Day - per Account Totals



Load Shape - Residential and Commercial

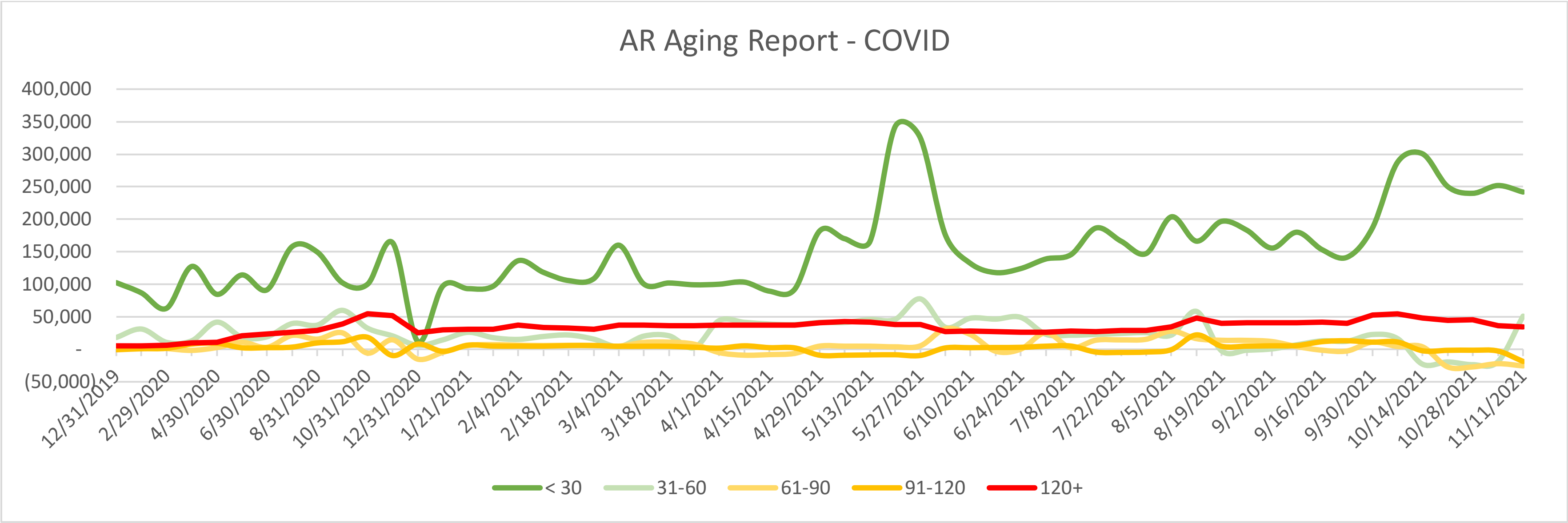
- Current reporting month is a partial data set.



Rock Island COVID-19 Update

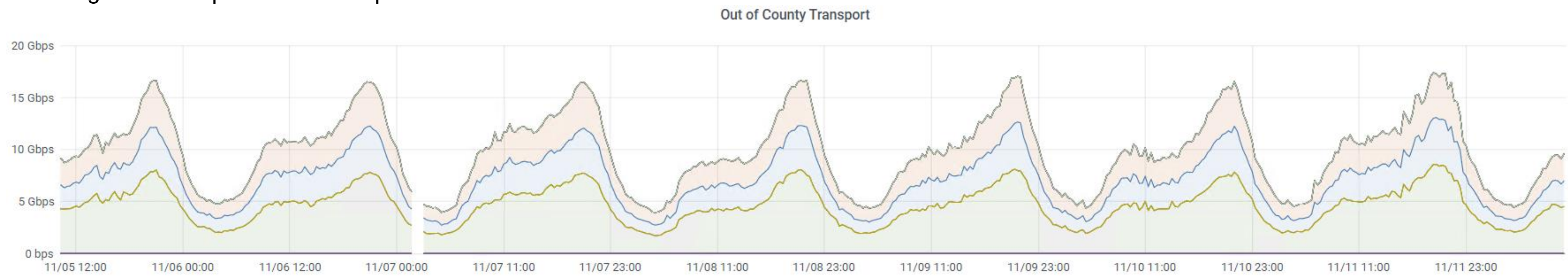
30-60-90 Accounts Receivable Trends

As staff works with long term debt accounts, the 120+ day category is beginning to recede. All other aging is within normal business fluctuations.



Transport Network

No changes in transport traffic to report.



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REPORTS

2021 Q3 Financial Report

Please see attached the full 2021 3rd quarter financial report. Included in the report package are the Statement of Revenues and Margins (along with a notable driver analysis), Balance Sheet, Statement of Cash Flows (GAAP), and capital projects budget tracking.

The energy charge adjustment (ECA) returned $734k ($211k in January based on December 2020 calculation) to the membership through Q3 2021, driven by higher kWh sales and a lower cost per kWh purchased than budgeted. The continued impact of COVID-19 on our commercial members is slightly notable as commercial revenue was below budget by ~$76k. Overall, sales were bolstered by higher kWh sales than budgeted. Coupled with overall expenses coming in under budget by ~$936k and the PPP Loan Forgiveness of $1.79M, all factors combined resulted in an increase in the margin of $2,941M as compared to budget.

The table below is a high-level projection of full-year 2021 financial results using actuals from Q3 and budget projections for future months.

Income Statement Summary (in thousands)	2021 Projection (actuals for prior months)		
	Budget	Projected	Variance
Operating Revenue	$ 31,454	$ 33,356	$ 1,902
ECA Surcharge / (Credit)*	-	(679)	(679)
Revenue	$ 31,454	$ 32,677	$ 1,223
Expenses:			
Cost of Purchased Power	9,735	9,526	$ (209)
Transmission & Distribution Expense	6,798	6,825	27
General & Administrative Expense	5,449	5,371	(78)
Depreciation, Tax, Interest & Other	8,698	8,316	(382)
Total Expenses	$ 30,680	$ 30,038	$ (642)
Operating Margin	774	2,639	1,865
Non-op margin	243	2,059	
Net Margin**	$ 1,017	$ 4,698	$ 3,681
OTIER	1.38	2.31	0.93
TIER	1.50	3.33	1.83
Equity %	35.8%	38.7%	2.9%
HDD	1,398	1,384	(14)
kWh Purchases	216,000	222,850	6,850
kWh Sales	203,260	209,482	6,222

* The ECA returned $679k to members in the form of bill credits through Oct 2021

** PPP Loan forgiveness recognized as non-operating revenue in Sept '21

For more detail, please note the following key points:

Heating Degree Days (HDD) were slightly lower than budgeted levels (actual of 865 vs. budget of 870). Overall kWh sales were 5.0M kWh above budget (155.0M vs. budget of 150.M) primarily resulting from residential revenue which is ~1.1% above budget.

2021 power purchases were $174k lower than budgeted, due to a combination of higher overall kWh purchases and a slightly lower cost/kWh than budgeted. Actual kWh purchases were 4M kWh above budget (163.8M vs. budget of 159.8M).

Excluding purchased power, Q2 YTD operating expenses were approximately $724k under budgeted amounts.

The ECA for 2021 was a net credit to members (and reduction to operating revenue) of $734k, or $36.25 for a member using 1000 kWh/month. Due to the one-month lag in billing the calculated ECA, ~$211k of the 2021 ECA was derived from December 2020 results.

Rock Island Communications 2021 Financials included in separate packet.

OPALCO 2021 Financial Package under separate cover.

General Manager

DASHBOARDS

Please review the dashboards at https://www.opalco.com/dashboards. Note that all the dashboards are within board approved strategic parameters.

Finance	Member Services	Outage
Budget Variance	Disconnects	Historical SAIDI - Graph
TIER/Margin	Uncollectable Revenue	Historical SAIDI - Figures
Expense	PAL	Outage Stats – Rolling 12 Mo
Cash	EAP	Outage Stats – Monthly
Power Cost	Service Additions	SAIDI by Category
Purchased Power	Annual Service Additions	Outage Summary
Annual Power Metrics	Revenue Dist. By Rate	
Capital		
Debt/Equity		
WIP		
Income Statement Trends		

ENGINEERING, OPERATIONS, AND INFORMATION TECHNOLOGIES

WIP

As of November 11, 2021, there are 409 work orders open totaling $7.94M. Decatur Energy Storage System is $1.5M of the balance. Operations has completed construction on 109 work orders, totaling $1.3M.

Safety

John Spain of Northwest Safety Service conducted Fire Safety training for operations and engineering staff. The total current hours worked without a loss time accident 129,139 hours.

Tidal

As a part of staff's ongoing conversations on tidal power, Orbital Marine, Pacific Northwest National Laboratory (PNNL), and OPALCO continue meetings for coordination of effort for the US DOE TEAMER grant, to Orbital and PNNL, and in preparation for the WA DOC grant for preliminary design. Staff expects the US DOE TEAMER report to be published by year end.

Grants

Washington Department of Commerce - Grid Modernization

- Decatur Battery Energy Storage System (ESS) (Grant $1M) (partnered with PNNL) – PNNL anticipates completion of final report in December. Staff is waiting final documentation from the vendor for close of work efforts.
- San Juan Microgrid (Grant $2.4M) (partnered with PNNL) – PNNL has completed initial analysis for hybrid storage to complete RDF development. HDR and staff are working towards a 60% design to allow the RFPs to be published to potential vendors.
- WA DOC CEF4 Grid Modernization Grants. OPALCO has received conditional award of the following projects. This conditional award awaits the negotiation of contracts with WA DOC and final approval to proceed.
    - San Juan Islands Tidal Generation Design (Phase 1 – Preliminary Design) – Scoping for WA DOC contract is underway.
    - Friday Harbor Ferry Electrification Design (Phase 1 – Preliminary Design) – Scoping for WA DOC contract is underway.
    - Orcas Biomass (Phase 2 – Detailed Design) – On hold until contracting for prior projects have been completed.

Washington Department of Commerce – Clean Energy Fund 3 Solar (partnered with PNNL)

- Low-Income Community Solar Deployment (Grant $1M) – RFP is 60% complete. Staff anticipates publishing to vendors in Q1 2022.

US Forest Service (minor in-kind efforts only)

- Biomass Generation with Biochar (60% Design Grant $72,835) – Contracts negotiation in progress.

FINANCE

2021 Budget Tracking

Energy (kWh) purchases and sales were higher than budgeted through October 2021. Overall, gross revenue surpassed budget by ~$1.3M, largely driven by increased kWh sales. This amount was curtailed by the ECA in the amount of $679k ($210k related to December 2020, one month billing lag) resulting in a net sales revenue variance of +$633k through October. Power cost is $180k under budget despite higher kWh purchases due to a lower cost/kWh than budgeted. The table presents full year 2021 projection with actuals through September & October where available.

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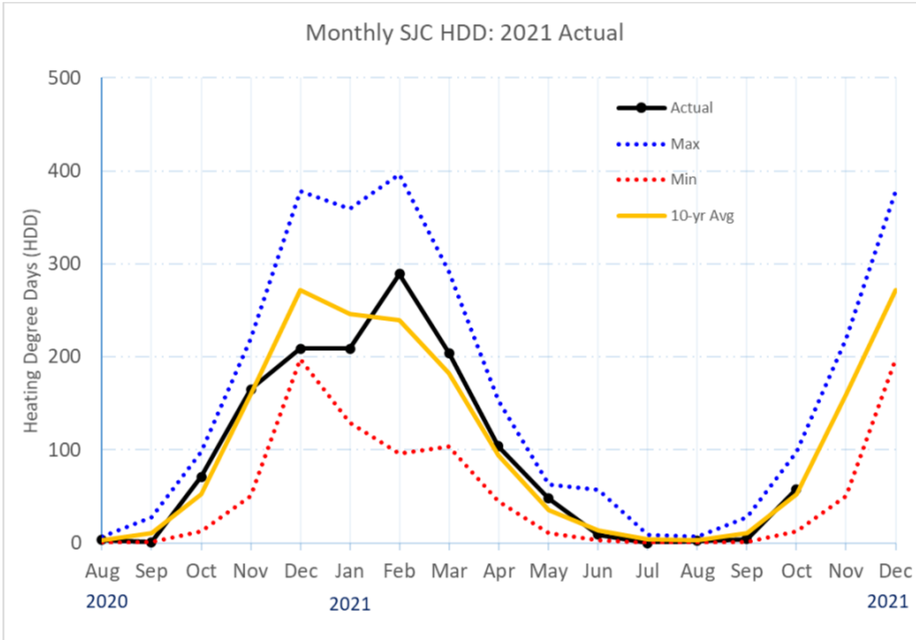
Monthly ECA

The calculated amount for the October ECA was a bill surcharge of $.003675 per kWh which collected $50,248 from members, or $3.68 per 1,000 kWh. The November billing period ECA is projected to be a bill credit of ($.003447) per kWh.

Heating Degree Days (HDD)

January 2021 began trending more towards an El Niño pattern though this flipped in February and March 2021 as HDDs came in above historical averages for the months. October has settled near the historic average.

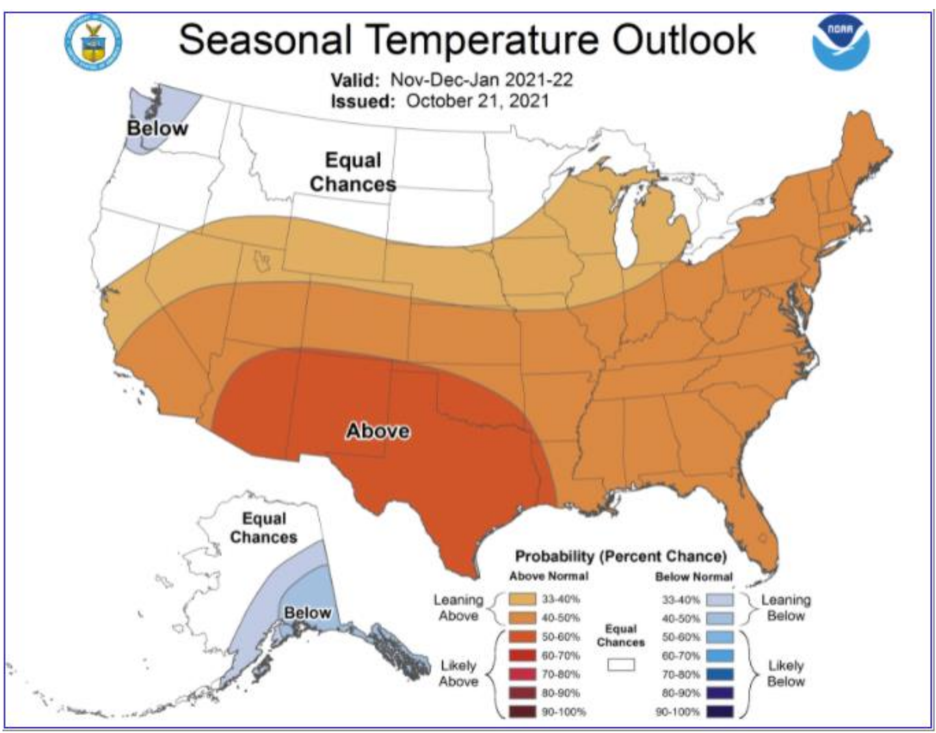


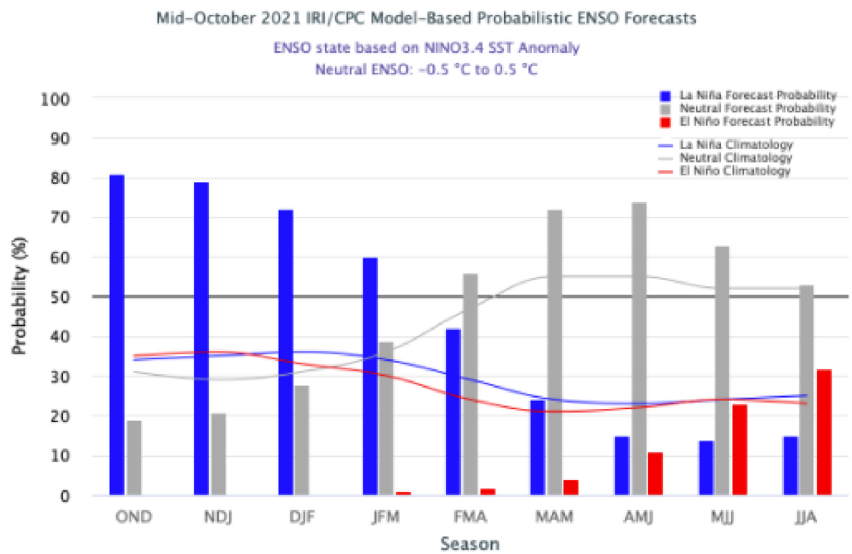
*10-year max, min, avg is 2010-2020

Weather Forecast

Looking ahead to the NOAA 'three-month outlook temperature probability' for Nov-Dec-Jan 2021 – 22, the outlook has shifted to 'leaning below' normal temperatures in our region for the winter. We continue to monitor these predictors monthly.

2021-22 Nov-Dec-Jan Outlook





Source: NOAA National Weather Service

MEMBER SERVICES

Energy Assistance

EAP: During October 2021, 333 members received ~$12.3k from the low-income Energy Assist program, compared to 367 members who received ~13.6k in assistance in October 2020.

Project PAL: During October 2021 16 Members received ~ $4.8K in Community/Family Resource Center Awards.

Covid Project PAL: During October 2021 13 Members received ~$1.1k in Awards.

T-RAP: Treasury funds for Rental Assistance and Utilities continue to be available through 2022.

Switch it Up!

There are now 209 projects complete and billing for a total of $1.68M outstanding. There are another 30 projects in various stages of the process. Some projects have been delayed as residential contractors have been limited by COVID-19.

Energy Savings

There were 12 rebates paid out to members totaling $11.7k. This includes 3 fuel switching ductless heat pump rebates and 1 EV charging station rebates.

Solar Interconnects

There were 7 new interconnect applications submitted in October, 3 members were interconnected with solar for a total of 499 (https://energysavings.opalco.com/member-generated-power/). There are an additional 19 pending connection.

Community Solar

During the October 2021 billing cycles, the Decatur Community Solar array produced 37,200 kWh. A total of ~$3,394 was distributed to 270 accounts.

COMMUNICATIONS

SOLAR
See energy roundtable summary.

Board Meeting Dates 2022 (Draft)
The 2021 Board and Rock Island Communications (RIC) meetings will be held via Zoom for the foreseeable future. With the exception of the RIC Budget meeting (Nov 17), staff supports joint OPALCO/RIC meetings. Proposed dates are as follows:

- January 20
- February 17
- March 17 OPALCO/RIC
- April 21 OPALCO Annual Business Meeting
- April 30 Member Annual Meeting
- May 19 OPALCO/RIC
- June 16
- July NO MEETING
- August 18 OPALCO/RIC
- September 15
- October 20
- November 17 RIC Budget Work Session
- November 18 OPALCO Budget
- December 15

EV Happy Deal
The final Happy Deal was used up this month. A total of 35 deals were utilized – OPALCO members qualified when purchasing a used electric vehicle from Island eCars. The deal included 35 Smart Home EV chargers and the installation costs covered (some installations pending), tab and licensing fees paid, 6 had additional sales covered (WA state covers up to $16K), and one member qualified to get on year of free charging for their EV.

Island Way Podcast
The latest Island Way Podcast where we interviewed Ductless Heat Pump Expert, Jonathan Moscatello about best practices for Ductless Heat Pumps and why they make so much sense in our region. This is the fourth episode in the Island Way Podcast series. Other episodes include topics such as Community Solar, Electric Vehicles and our Island Way Campaign – outlining our energy future. Find episodes at www.opalco.com/islandway.

Member stories
The latest members story is a multigeneration family on San Juan Island. Read up on this energetic farming family who takes efficiency and conservation seriously: https://energysavings.opalco.com/meet-christine-and-zach-chan-an-energetic-farming-family/

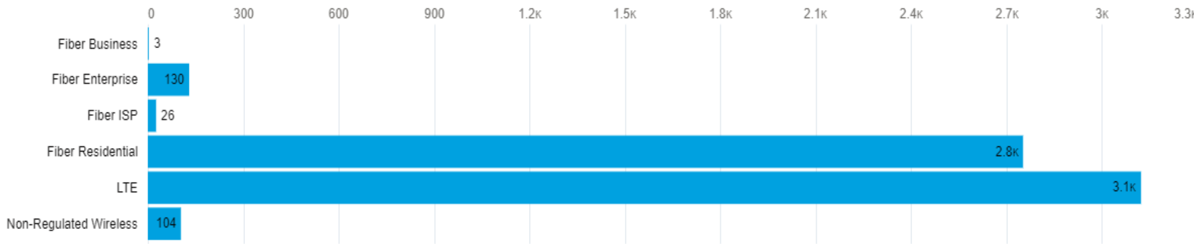
Clean Energy Implementation Plan (CEIP)
Staff are completing the Dept of Commerce required reporting, which is due January 1, 2022. PNGC staff are supporting utilities in this exercise. A member comment opportunity is required and planned for the December 16 board meeting.

- November 29 – Timeline published
- December 1 – Draft CEIP for review
- December 16 – Board review and member comments
- December 20 – Media Release: CEIP and member feedback
- December 29 – Submit CEIP to Commerce

OPALCO

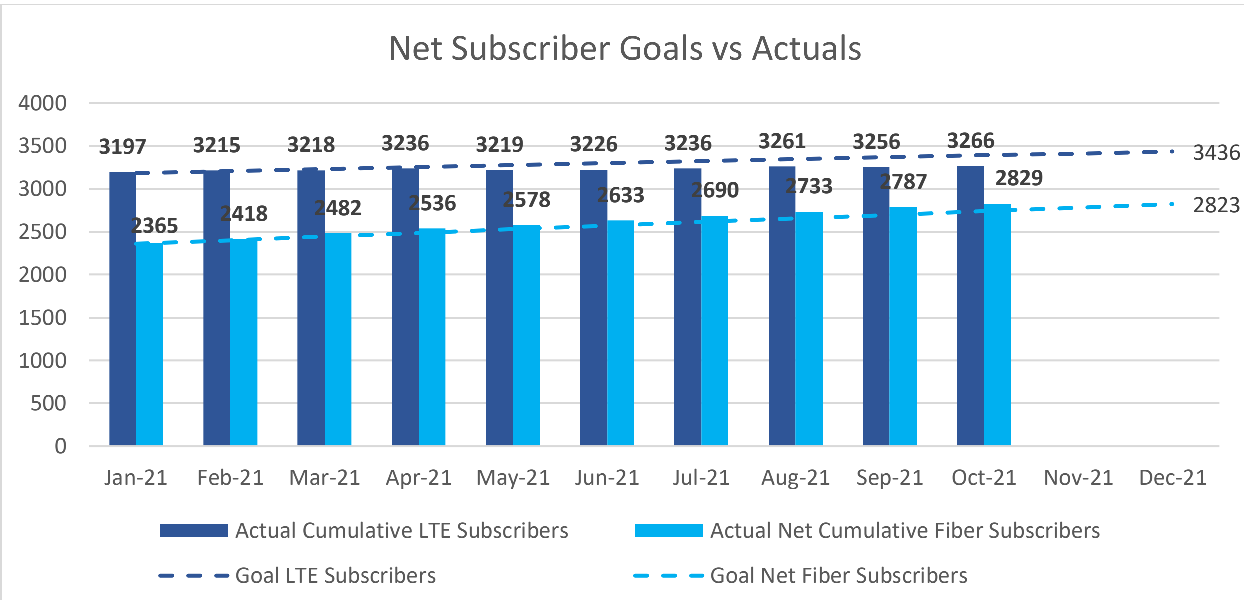
Co-op Run. Community Powered.

Rock Island Snapshot

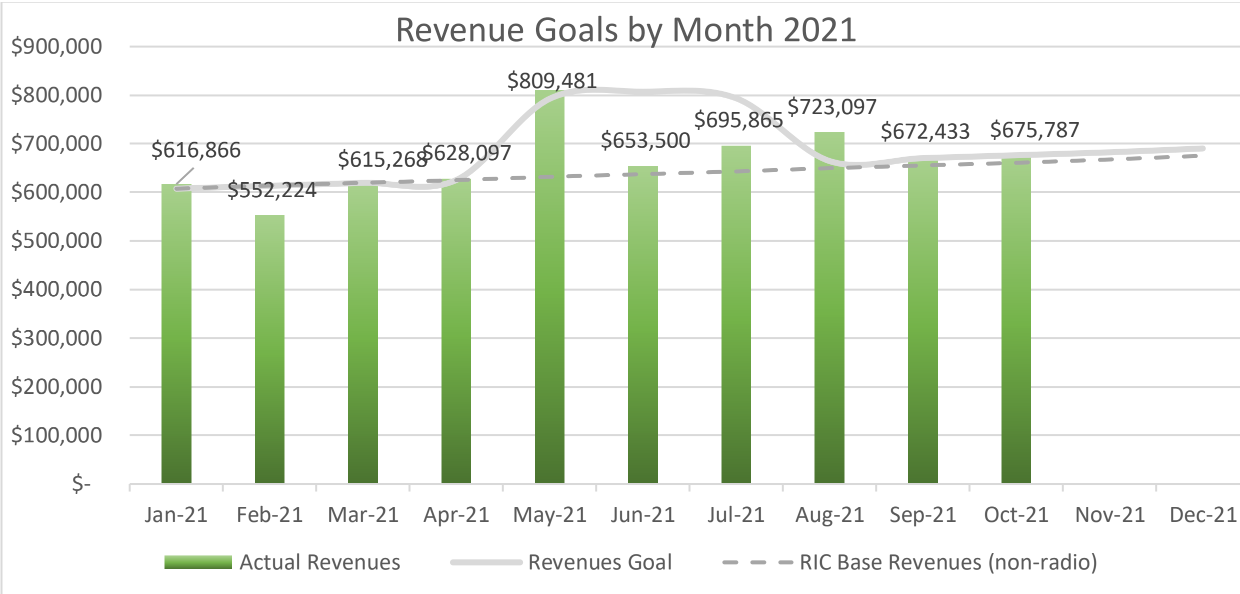


6,138 Internet Service Customers

Net Subscribers 2021



Revenues



❖Oct revenues are not closed and subject to change.