NewSun ENERGY

April 19, 2021

Via Electronic Filing

Oregon Public Utility Commission
Attention: Filing Center
201 High Street, Suite 100
Post Office Box 1088
Salem, OR 97308-1088

Re: LC 73 PGE IRP Update – Supplemental Comments

Dear Commissioners:

NewSun Energy LLC (NewSun) provides these supplemental comments in advance of the April 20, 2021 Special Public Meeting regarding Portland General Electric's (PGE's) Integrated Resource Plan (IRP) Update. NewSun previously submitted comments on PGE's IRP Update on March 10, 2021 and comments on the Staff Report on April 12, 2021.

EXECUTIVE SUMMARY

Commissioners, PGE's proposed update is based on a **blatantly bad underlying solar forecast**[1]**,** over-assumptions on solar projects by distortingly **cherry-picked "IRP snapshot" date** (just weeks before ~100 MW of known QF PPAs COD deadlines and other terminations), PGE **cherry-picking only downward pressuring inputs to update**, and **omissions of other material changes expected** like PGE's 100% corporate clean commitment, obviously likely requiring more renewables generation.

As discussed below, PGE's bad solar forecast input is triply problematic because—in addition to combining a prior unlikely system design with a bad forecast for that unlikely system, netting output **17% low** —PGE then stacks those bad forecasts on an overestimation of QF solar projects. Worse, the "short" *disproportionately affects key shoulder hours and winter days where PGE needs energy and capacity*. **This also distorts the heat map** PGE produces, making it non-reflective, visually and numerically, of expected system needs vs solar output**.**

The net effect of this is PGE trying to shift an *already improbably low 15.5% capacity contribution* for Oregon High Desert solar—*based on the same flawed study they've been using since 2019* (as we flagged in the IRP Update process—*down further to 5.5%*, basically a comical number[2]. Adding insult to injury—because these numbers were wrong for the past couple years—and are now *amplified* through surrounding input update cherry picking, perpetuation of known questionable assumptions, and ignoring upward pressures. PGE now asks to make the prior problem worse, instead of correcting it.

[1] See discussion and **charts** below.
[2] Meanwhile the E3 2019 report PGE included in its 2019 IRP stated PNW *solar could be expected to contribute 26% in Winter and 81% in Summer*.

Based on this, PGE asks for an IRP Update acknowledgement—for the sole purpose *of* avoided cost updates. The Commission should not acknowledge (i.e. encourage) this.

*The correct, fair, and expedient action—in face of these competing tensions and process—when other forces and facts point that these numbers should go up, not down, is to **leave avoided costs alone**—no formal acknowledgment and/or direct PGE to make no update to avoided costs.*

<u>Note</u>: This proposal also has the benefit of avoided substantial, contentious near-term work, process, arguments—and will allow Staff to focus on other PURPA dockets, and the surrounding processes that, in combination with PGE *full* IRP update, collectively allows all these matters to be comprehensively addressed together. It also avoids issues of discriminatory price updates, as related PURPA standards, as raised in our April 12, comment letter.

In these comments, NewSun:

(1) Provides additional data, examples, and considerations for the Public Utility Commission of Oregon (Commission) to consider at the special public meeting, as context for the erroneousness of PGE's proposed update; and

(2) Requests that the Commission <u>not acknowledge</u> PGE's 2019 Update, because by doing so the Commission would thereby:

(i) **Condone a mix of erroneous information and questionable actions by PGE,** *all of these actions solely move in one direction*: *to drive downward, with apparent bias, avoided cost prices inappropriately. Various considerations which could have pushed prices up were excluded from discussion (including items asked in IRP Update process to be included; PGE changed nothing).*

(ii) **Limit unreasonably and unfairly addressable issues in the avoided cost update process that would follow.** If PGE goes through an entire 10 month process to do an "IRP Update", *the sole purpose of which is "updating avoided costs", how is it then fair for PGE to exclude contravening inputs?* Much less if some of them are bogus, questionable, or reasonably point in the opposite direction. It's not.

Acknowledgement by the Commission would inappropriately encourage -such behavior—cherry-picking inputs and ignoring critical feedback in the IRP Updates process—which of course further undermines whatever purpose and integrity the IRP Update is supposed to have.

(3) In the alternative, if the Commission is not willing to deny PGE an acknowledgement—again noting that such denial would have no adverse impact on any PGE procurement, RFP, or other plans—**NewSun asks that the PUC either**:

(i) **Use Commission's "discretion at [this] time to direct [PGE] to waive its 30-day post IRP update avoided cost update"[3],** which is a practical "split the baby"

3

approach, if PGE argues some acknowledgement must occur for its RFP plans (though contrary to written filings about the Update purpose); and/or

(ii) **Require critical IRP pieces be kept open, not just those formally updated**, in addition to PGE's QF PPA failure rate assumptions (which Staff plans to query)**:**

a. Solar Input Forecast, including the HDR study, stacking "same location" solar projects, and related issues;
b. PGE's 100% Clean Commitment
c. Load forecast change projections
d. LOLE, LOLH, LOLP modeling

e. Additional:
   i. CTs: Gas Turbines shouldn't be used as avoided resource; last gas plant just died.
   ii. PGE's actions to address the Governor's Executive Order 20-04 and the PUC's associated workplan;
   iii. Updated analysis on distributed flexibility, which can help support variable renewable resources;
   iv. Incorporating its already completed Colstrip Enabling Study which reviewed scenarios for early removal of Colstrip from PGE's portfolio;
   v. Analysis on the impacts of climate change on its loads;
   vi. Major regional capacity shortages;
   vii. Lack of Transmission Capacity for avoided resources;
   viii. The fact that the 2019 IRP Update preferred portfolio shows that PGE has less near-term dispatchable capacity than the 2019 IRP preferred portfolio, and it includes additional renewables in 2023;

Another simple, practical approach would be for the Commission to just require PGE to remove all non-COD'd projects that were included at 6/15/20, re-run numbers, **AND** ensure the solar QF prices are not below the wind prices, given PGE's 100% clean commitment and given planned wind procurement activity.

DATA, EXAMPLES, AND DISCUSSION RE: Questionable and Erroneous PGE Inputs

QF Snapshot Date

PGE picked a gamed, bad faith "snapshot" date for QFs COD pipeline, picking June 15th, 2020 just before numerous QF PPAs would 'time out'—but then somehow assumed ~all of those would COD successfully by two weeks later on July 1, 2020.

- **98-167 MW of the 466 MW claimed "expected" QFs were dead**, failed shortly thereafter, and/or PGE sent termination notices in couple months after "snapshot".
- **100 MW of claimed had Outside COD** drop-dead dates 2-6 weeks after June 15th.
- **50 of the 71 PPAs (70% of contracts) had July 1st as their "IRP Update Estimated Start Date"**—that PGE claimed to expect to COD on June 15th snapshot. i.e. PGE

claimed *all* these should count for next 2 years until IRP done, just a couple weeks before they would time out.

PGE has sent numerous termination notices subsequently… but in IRP Update process, when asked said, essentially, "sorry our snapshot date, well, we had to pick something…" we were told, as if it were innocuously chosen, and subsequent review of data has shown was not the case.

The effect of PGE picking June 15, 2021 for its snapshot date, therefore, drastically overstates the amount of solar in its baseline portfolio and a critical input driving the ELCC value for solar down from 15.8% to just 5.5%[4]. This is in addition to the overstatement of community solar resources as indicated in prior comments in this docket.

<u>CONTEXT</u>*:*

- PGE's stated *sole* purpose of update was to update avoided cost pricing—*not to change their action plan*.
- 10 months has passed since "snapshot"
- PGE chose ALL the dates in their IRP Update schedule
- 4-5 months has passed since PGE's "100% clean" goal announced.
- All these QF PPAs timing out is a long foreseen, known schedule issue, borne of when pricing update behavior by PGE in 2020 resulted in numerous PPAs signed in June/July of 2016. Add four years, here we are.

<u>BAD SOLAR FORECAST DISCUSSION</u>

PGE's 2019 HDR study low-balls solar production 11% to 28%[5] to the material and unfair detriment of solar ELCC. Several examples follow. These affects are amplified by application and nature of the shortcomings, being over-affected in key shoulder hours, for example, when PGE has need, as well as distorting their LOLE heat map—both as outputs (prior bad inputs) and then with new bad data overlaid on top of that.

HDR's forecast (24.8% CF for 1.3 DC:AC) is 11% low relative to *expected* generation from a comparable 1.3 DC:AC system AT THE SAME LOCATION[6].

At 1.5 DC:AC (30.0% CF), like the 40 MW just built by NewSun in 2020, PGE's forecast is 20+% low

Much less as compared to expected system designs, which could range up to 1.7 DC:AC ratios (31.8% CF). Which would be 28% low. These issues are particularly acute in shoulder hours.

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[4] While several projects begun commercial operations since that date (or are expected to), and should appropriately be included in PGE's baseline analysis, PGE issued termination notices on several more and a number of the projects are not viable. Of the 108 QF projects (totaling 466 MW) included in PGE's June 15, 2020 snapshot date, 38 (totaling 137 MW) were operating as of that date and the remaining 70 (totaling 329 MW) had not yet reached commercial operations. Specifically, NewSun estimates that between 100 and 160 MWs should be excluded for these reasons.

[5] Range for same system design (1.3) in same location, to max likely system (1.7), with 1.5 in the middle, 20% low.

[6] NewSun ran model comparisons based on publicly available NSRDB solar data for the same Fort Rock area. These models validated with actual system performance seen in 2020 in the same area, as well as I.E. reports for same.

Table 4.4-2. Solar Plant Plant Availbility/Reliability

Availability/Reliability		Solar PV 25 MWa
Forced Outage Rate	%	0%
Planned Outage Rate	%	2%
Mean Annual Outage Duration	Days/year	7.3

The HDR forecast includes **seriously problematic assumptions like assuming 7.3 days of outages** per year. **That's just absurd.** Solar facilities don't really take outages; they can turn off single strings, rows, and inverters IF maintenance can't be done at night.

Table 4.3-1. Solar Site Nameplate Capacity and Net Annual Averaged Degraded Capacity Factor

Solar PV Site	Nameplate Capacity (MW)	Annual NCFs (%)
Christmas Valley	95	24.8%

In short, we'd expect roughly 30.0%CF from likely systems[7]; yet PGE/HDR suggest 24.8% CF.

And the nature of "low" here means that their forecast effectively "slides" the entire daily output bell curve *downward* and thereby disproportionately "shorts" key time periods, particularly the daily shoulder hours, such as late summer afternoons, as well as "shorts" winter daytime input—all of which times align substantially with PGE's need. The net effect of these assumptions is in stark contrast with expected system outputs.

All of which is made worse because PGE then stacks up their bad over-counted solar forecast on top of the overcounted QF solar projects—modeling *all* of these projects as if *at the exact same geographic location*, repeating and *stacking* this bad output data—*each* of which problems *amplifies* each of those problems. (Among many other deficiencies.)

Thus the LOLE heat map PGE is showing you in this update—in addition to undervaluing new solar's ability to contribute thereto—**is distorted by both over-estimating solar online AND mis-assessing that "expected" solar's contributions.** Their "worst hours" would thus shift further into daytime with these fixed, as would solar contribution to shoulders.

[7] NewSun financed and constructed four 10 MW systems in the Oregon High Desert in 2020, thus speaks based on direct recent on-location experience, in addition to 15 years of experience. All four projects, along with four more nearby were 1.5 DC:AC ratio systems. 30% CF aligns with the Independent Engineering reports for these systems.

EXAMPLES ON "HOW SHORT" PGE's STUDY IS

(1) **The following shows *expected* generation from relevant systems at the same rough location** in Fort Rock, Oregon (i.e. under the powerlines projects would connect to, in same area of Oregon's best solar resource) *as compared to what PGE's HDR study assumes.* ***Their project basically NEVER produces nameplate.***

DC:AC Ratios vs Output Levels	Total Hours > (	Hours > 1 MW	Hours > 7 MW	Hours > 8 MW	Hours > 9 MW	*Hours = 10 MW
PGE/HDR "1.3"	4197	3602	1557	1272	**0**	**0**
Normal 1.3	4197	3650	1819	1514	1262	997
Normal 1.5	4199	3701	2081	1836	1575	1351
Normal 1.7	4199	3739	2298	2064	1849	1643

% at MW-level for all NON-ZERO GEN Hours		> 1 MW	Hours > 7 MW	Hours > 8 MW	Hours > 9 MW	Hours = 10 MW
PGE/HDR "1.3"		86%	37%	30%	**0%**	**0%**
Normal 1.3		87%	43%	36%	30%	24%
Normal 1.5		88%	50%	44%	38%	32%
Normal 1.7		89%	55%	49%	44%	39%

(2) **"Deletion" of Output to Match PGE/HDR:** For context, here's how many hours of an expected system you'd need to "delete" to match PGE's assumptions, as a proxy, to get to 24.8% CF assumed:

10 MW AC PV Solar with 1.5 DC/AC Ratio - Expected Hourly Generation by Month (average MW)

Hour Beg.	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6	0.0	0.0							0.0	0.0	0.0	0.0
7	0.0											0.0
8				7.1	7.9	9.2	8.7					
9		5.9	6.3	7.5	8.3	9.2	8.8	9.0	8.7	7.4	4.4	
10	4.7	6.1	6.9	7.9	8.5	9.4	8.7	9.3	8.2	7.9	4.5	3.7
11	4.3	6.2	7.6	8.3	8.9	9.5	9.2	9.6	8.4	7.8	4.4	3.6
12	4.1	6.0	7.4	8.4	9.0	9.3	8.9	9.3	8.6	7.5	4.4	3.5
13	5.8	6.2	7.5	7.8	8.9	9.4	9.2	9.5	8.8	7.3	5.7	4.5
14		6.4	7.1	7.7	8.9	9.1	9.1	9.4	8.3	7.5	5.6	
15		5.9	7.1	7.7	8.6	9.0	8.9	8.8	7.8	7.8		
16				7.2	7.9	8.8	8.9	8.4	7.9			0.0
17	0.0			6.5	7.6	8.5	8.4	8.1			0.0	0.0
18	0.0	0.0	0.0			7.1	6.6				0.0	0.0
19	0.0	0.0	0.0						0.0	0.0	0.0	0.0
20	0.0	0.0	0.0	0.0	0.0			0.0	0.0	0.0	0.0	0.0
21	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
22	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
23	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Shows "deleting" year-round solar shoulder hours from expected output until %CF matches PGE's 24.8%. From a likely system design, 1.5 DC:AC ratio.

1.3 DC/AC Ratio - Hourly Generation Percent of Nameplate (%)												
Hour Beg.	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
1	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
3	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
4	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
5	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
6	0%	0%	2%	0%	16%	27%	18%	2%	0%	0%	0%	0%
7	0%	3%	28%	29%	50%	66%	55%	41%	18%	1%	4%	0%
8	15%	33%	54%	65%	76%	90%	84%	80%	56%	34%	26%	13%
9	39%	53%	60%	73%	80%	91%	86%	87%	83%	66%	38%	30%
10	41%	54%	64%	75%	81%	93%	85%	90%	77%	72%	39%	32%
11	37%	54%	69%	79%	85%	93%	90%	93%	80%	70%	38%	31%
12	35%	52%	68%	79%	86%	91%	86%	89%	80%	66%	38%	31%
13	50%	54%	69%	74%	85%	91%	89%	90%	81%	64%	49%	39%
14	55%	57%	67%	74%	84%	88%	89%	89%	78%	66%	48%	36%
15	34%	52%	67%	74%	82%	88%	87%	85%	74%	70%	23%	16%
16	3%	22%	44%	70%	76%					52%	0%	0%
17	0%	0%	11%	61%	72%					19%	0%	0%
18	0%	0%	0%	30%	45%					0%	0%	0%
19	0%	0%	0%	1%	14%					0%	0%	0%
20	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
21	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
22	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
23	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

Shows "deleting" SUMMER PM shoulder hours from expected output until %CF matches PGE's 24.8%. From a 1.3 DC:AC, i.e. what PGE's forecast should look like if same design.

(3) **Solar Generation compared to PGE's RVOS Heat Map**

	PGE RVOS LOLP											
Hour Beg.	1	2	3	4	5	6	7	8	9	10	11	12
0	0.00004	0.00003	0.00000	0.00000	0.00000	0.00000	0.00000	0.00001	0.00000	0.00000	0.00002	0.00013
1	0.00001	0.00001	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00003
2	0.00000	0.00001	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00002
3	0.00001	0.00001	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00003
4	0.00003	0.00003	0.00001	0.00001	0.00000	0.00000	0.00000	0.00000	0.00000	0.00000	0.00002	0.00008
5	0.00053	0.00042	0.00019	0.00007	0.00000	0.00000	0.00000	0.00000	0.00001	0.00005	0.00050	0.00111
6	0.00187	0.00146	0.00128	0.00017	0.00000	0.00000	0.00002	0.00008	0.00012	0.00034	0.00212	0.00447
7	0.00745	0.00399	0.00270	0.00034	0.00002	0.00002	0.00014	0.00041	0.00039	0.00065	0.00464	0.00980
8	0.01268	0.00684	0.00303	0.00020	0.00003	0.00006	0.00052	0.00156	0.00046	0.00050	0.00840	0.01571
9	0.01009	0.00459	0.00210	0.00015	0.00005	0.00017	0.00150	0.00330	0.00067	0.00028	0.00679	0.01425
10	0.00745	0.00316	0.00133	0.00007	0.00009	0.00037	0.00321	0.00600	0.00093	0.00020	0.00501	0.01145
11	0.00626	0.00202	0.00068	0.00005	0.00013	0.00070	0.00535	0.00923	0.00142	0.00015	0.00390	0.00955
12	0.00579	0.00122	0.00034	0.00003	0.00023	0.00130	0.00830	0.01330	0.00208	0.00011	0.00340	0.00707
13	0.00470	0.00064	0.00021	0.00002	0.00031	0.00198	0.01219	0.01809	0.00324	0.00009	0.00285	0.00529
14	0.00359	0.00050	0.00015	0.00002	0.00042	0.00259	0.01549	0.02203	0.00483	0.00011	0.00246	0.00417
15	0.00312	0.00055	0.00013	0.00001	0.00049	0.00339	0.01815	0.02515	0.00652	0.00015	0.00299	0.00555
16	0.00503	0.00097	0.00024	0.00002	0.00063	0.00394	0.01892	0.02648	0.00787	0.00037	0.00524	0.01275
17	0.01244	0.00261	0.00058	0.00003	0.00063	0.00333	0.01784	0.02654	0.00837	0.00102	0.01192	0.02240
18	0.01993	0.00582	0.00157	0.00005	0.00059	0.00228	0.01473	0.02478	0.00777	0.00163	0.01826	0.02930
19	0.01924	0.00687	0.00231	0.00010	0.00048	0.00144	0.01123	0.02014	0.00693	0.00137	0.01672	0.02619
20	0.01404	0.00486	0.00158	0.00008	0.00025	0.00076	0.00691	0.01483	0.00562	0.00056	0.01192	0.01832
21	0.00797	0.00259	0.00049	0.00003	0.00009	0.00027	0.00286	0.00797	0.00150	0.00010	0.00640	0.01030
22	0.00420	0.00128	0.00007	0.00000	0.00000	0.00002	0.00014	0.00083	0.00004	0.00008	0.00222	0.00504
23	0.00061	0.00017	0.00000	0.00000	0.00000	0.00000	0.00001	0.00006	0.00000	0.00001	0.00034	0.00088

1.5 DC/AC Ratio - Expected Hourly Generation by Month (average MW)												
Hour Beg.	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
0	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
1	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
3	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
4	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
5	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
6	0%	0%	3%	0%	18%	31%	21%	2%	0%	0%	0%	0%
7	0%	4%	33%	33%	58%	76%	63%	48%	21%	1%	5%	0%
8	18%	39%	59%	71%	79%	92%	87%	88%	65%	40%	30%	15%
9	45%	59%	63%	75%	83%	92%	88%	90%	87%	74%	44%	34%
10	47%	61%	69%	79%	85%	94%	87%	93%	82%	79%	45%	37%
11	43%	62%	76%	83%	89%	95%	92%	96%	84%	78%	44%	36%
12	41%	60%	74%	84%	90%	93%	89%	93%	86%	75%	44%	35%
13	58%	62%	75%	78%	89%	94%	92%	95%	88%	73%	57%	45%
14	64%	64%	71%	77%	89%	91%	91%	94%	83%	75%	56%	42%
15	39%	59%	71%	77%	86%	90%	89%	88%	78%	78%	27%	18%
16	4%	25%	51%	72%	79%	88%	89%	84%	79%	60%	0%	0%
17	0%	0%	13%	65%	76%	85%	84%	81%	58%	22%	0%	0%
18	0%	0%	0%	35%	52%	71%	66%	51%	19%	0%	0%	0%
19	0%	0%	0%	1%	17%	33%	28%	10%	0%	0%	0%	0%
20	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
21	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
22	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
23	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

While this doesn't *exactly align*, it certainly doesn't look like PGE's proposed **5.5%** contribution.

Alignment of NewSun Estimates with ACTUAL Generation, SAME location, 2020.

1.5 DC/AC Ratio				ACTUALS, Fort Rock Solar IV		ACTUAL % of Nameplate	
HrBeg	HrEnding	Jul	Aug	Jul	Aug	Jul	Aug
0	1	0%	0%	-	-	0%	0%
1	2	0%	0%	-	-	0%	0%
2	3	0%	0%	-	-	0%	0%
3	4	0%	0%	-	-	0%	0%
4	5	0%	0%	-	-	0%	0%
5	6	0%	0%	-	-	0%	0%
6	7	21%	2%	1.2	0.3	12%	3%
7	8	63%	48%	6.1	3.7	61%	37%
8	9	87%	88%	9.5	7.8	95%	78%
9	10	88%	90%	9.6	9.0	96%	90%
10	11	87%	93%	9.7	9.4	97%	94%
11	12	92%	96%	9.9	9.4	99%	94%
12	13	89%	93%	9.8	9.5	98%	95%
13	14	92%	95%	9.7	9.0	97%	90%
14	15	91%	94%	9.6	8.9	96%	89%
15	16	89%	88%	9.5	9.1	95%	91%
16	17	89%	84%	8.8	8.2	88%	82%
17	18	84%	81%	9.0	7.7	90%	77%
18	19	66%	51%	8.1	5.5	81%	55%
19	20	28%	10%	3.8	1.5	38%	15%
20	21	0%	0%	-	-	0%	0%
21	22	0%	0%	-	-	0%	0%
22	23	0%	0%	-	-	0%	0%
23	24	0%	0%	-	-	0%	0%

HrBeg	HrEnding	7	8
0	1	0.000000	0.000014
1	2	0.000000	0.000002
2	3	0.000000	0.000000
3	4	0.000000	0.000000
4	5	0.000000	0.000000
5	6	0.000000	0.000003
6	7	0.000021	0.000077
7	8	0.000136	0.000406
8	9	0.000518	0.001555
9	10	0.001504	0.003302
10	11	0.003207	0.006001
11	12	0.005352	0.009232
12	13	0.008302	0.013302
13	14	0.012188	0.018090
14	15	0.015491	0.022027
15	16	0.018148	0.025149
16	17	0.018921	0.026483
17	18	0.017835	0.026538
18	19	0.014734	0.024779
19	20	0.011230	0.020143
20	21	0.006910	0.014833
21	22	0.002864	0.007969
22	23	0.000139	0.000833
23	24	0.000005	0.000056

Figure _ – Fort Rock Solar IV generation production July/August
Side by side with PGE RVOS Loss of Load Data

NewSun gathered solar generation data for the Fort Rock Solar IV project for the months of July and August. This project began commercial operation on June 29, 2020, it located in the same area as the proxy resource used in PGE's 2019 IRP HDR study, and sells its output to PGE. It has a DC/AC ratio of 1.5, compared to the 1.3 DC/AC ratio PGE used for its proxy resource. This project's solar production data shows that between the hours of 8:00 am and 6:00 pm, the generation is nearly running at peak capacity (see Figure 1).

When compared to PGE's highest loss of load hours provided in the RVOS proceeding, we see that the incidence of solar generation to be highly correlated with these summer afternoon needs. As noted in Figure 2, PGE's highest need hours are between 3:00 pm and 6:00 pm with still high need in the hours immediately surrounding those times.

OTHER FACTORS NOT UPDATED

- **PGE's new and ambitious climate goals to decarbonize**, which include a commitment to reducing its 2010 baseline greenhouse gas (GHG) emissions by 80% by 2030 and a goal of zero GHG emissions by 2040 -- and related multi-GW procurement needed for the same;
- **PGE's actions to address the Governor's Executive Order** 20-04 and the PUC's associated workplan;

- **Updated analysis on distributed flexibility, which can help support variable renewable resources;**
- **Colstrip Removal:** Incorporating its already completed Colstrip Enabling Study which reviewed scenarios for early removal of Colstrip from PGE's portfolio;
- **Climate Load Impacts:** Analysis on the impacts of climate change on its loads;
- **Major regional capacity shortages;**
- **The inability to develop CTs as avoided resources;**
- **Lack of Transmission Capacity for avoided resources;**
- **The fact that the 2019 IRP Update preferred portfolio shows that PGE has less near-term dispatchable capacity than the 2019 IRP preferred portfolio, and it includes additional renewables in 2023**;

CONCLUSION

The Commission should not permit PGE to compound the errors in its underlying proxy resource assumptions with selective updates that overstate the amount of solar generation in its baseline portfolio. To do otherwise, creates discriminatory pricing for qualifying facilities and will result in fundamentally incorrect avoided cost prices that will not be corrected for years.

The Commission should therefore not acknowledge PGE's cherry-picked updates, but direct PGE to correct its ELCC in the next IRP.

Acknowledgement by the Commission would inappropriately encourage -such behavior—cherry-picking inputs and ignoring critical feedback in the IRP Updates process—which of course further undermines whatever purpose and integrity the IRP Update is supposed to have.

In the alternative, if the 2019 Update *is* acknowledged, *the Commission should direct PGE to not update avoided costs at this time.*

Or, if the above simple solutions aren't adopted, and if avoided costs will be updated, ensure that proper suite of factors, as above, are included, so factors aren't artificially limited by PGE's cherry-picking.

Sincerely,

Jake Stephens
CEO
NewSun Energy