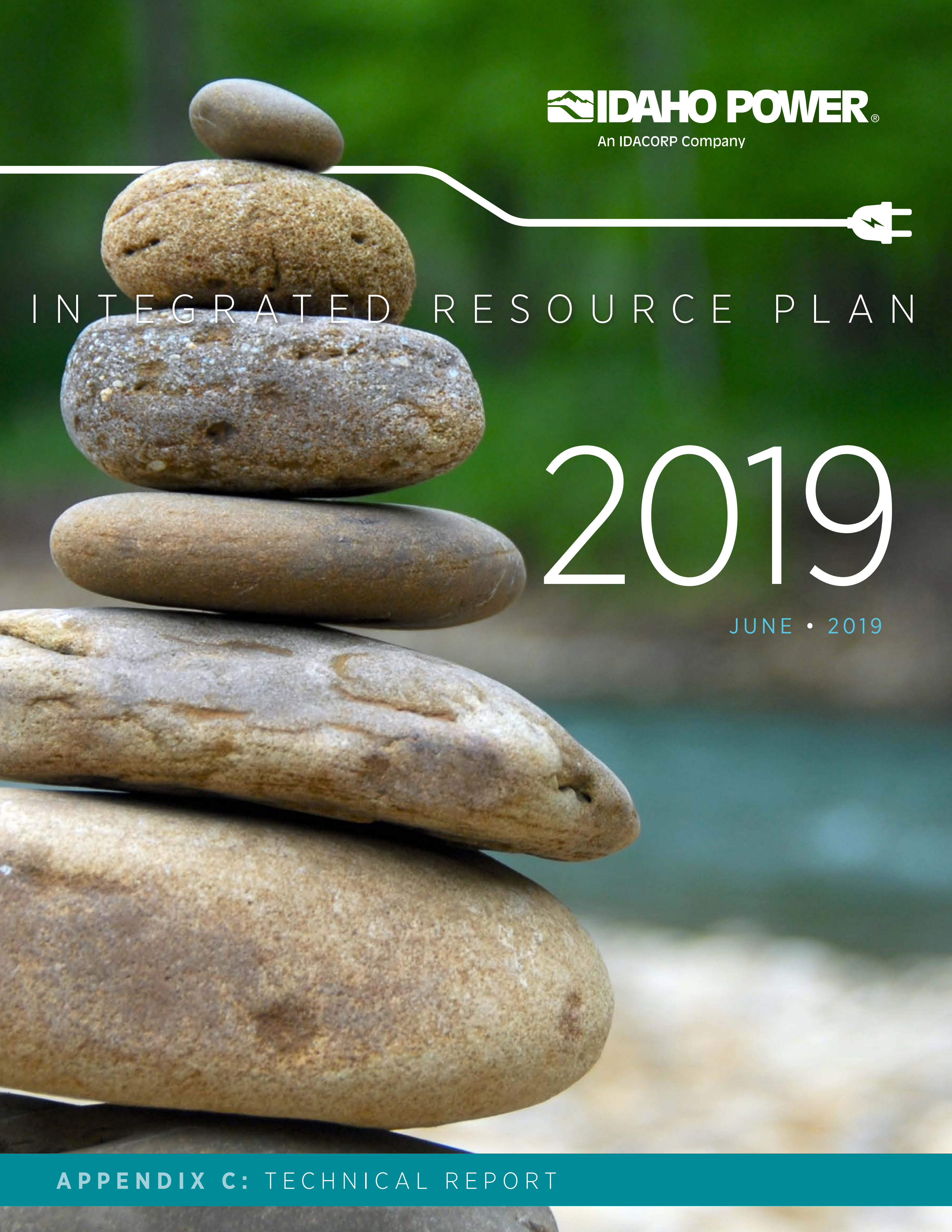

IDAHO POWER®

An IDACORP Company

INTEGRATED RESOURCE PLAN

2019

JUNE • 2019

APPENDIX C: TECHNICAL REPORT

SAFE HARBOR STATEMENT

TABLE OF CONTENTS

INTRODUCTION

Appendix C–Technical Appendix contains supporting data and explanatory materials used to develop Idaho Power's *2019 Integrated Resource Plan* (IRP).

The main document, the IRP, contains a full narrative of Idaho Power's resource planning process. Additional information regarding the 2019 IRP sales and load forecast is contained in *Appendix A–Sales and Load Forecast*, details on Idaho Power's demand-side management efforts are explained in *Appendix B–Demand-Side Management 2018 Annual Report*, and supplemental information on Boardman to Hemingway (B2H) transmission is provided in *Appendix D–B2H Supplement.* The IRP, including the four appendices, was filed with the Idaho and Oregon public utility commissions in June 2019.

For information or questions concerning the resource plan or the resource planning process, contact Idaho Power:

Idaho Power—Resource Planning

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Boise, Idaho 83702

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IRP Advisory Council

Idaho Power has involved representatives of the public in the IRP planning process since the early 1990s. This public forum is known as the IRP Advisory Council (IRPAC). The IRPAC generally meets monthly during the development of the IRP, and the meetings are open to the public. Members of the council include regulatory, political, environmental, and customer representatives, as well as representatives of other public-interest groups.

Idaho Power hosted eight IRPAC meetings, including a workshop designed to explore the potential for distributed energy resources to defer grid investment. Idaho Power values these opportunities to convene, and the IRPAC members and the public have made significant contributions to this plan.

Idaho Power believes working with members of the IRPAC and the public is rewarding, and the IRP is better because of public involvement. Idaho Power and the members of the IRPAC recognize outside perspective is valuable, but also understand that final decisions on the IRP are made by Idaho Power.

Customer Representatives	
Agricultural Representative	Sid Erwin
Boise State University	Barry Burbank
Idaho National Laboratory	Kurt Myers
Micron	Clancy Kelley
St. Luke's Medical	Mark Eriksen
Public-Interest Representatives	
Boise Metro Chamber of Commerce	Ray Stark
Boise State University Energy Policy Institute	Kathleen Araujo
City of Boise	Steve Burgos
Idaho Conservation League	Ben Otto
Idaho Legislature	Representative Robert Anderst
Idaho Office of Energy and Mineral Resources	John Chatburn
Idaho Sierra Club	Mike Heckler
Idaho Technology Council	Jay Larsen
Idaho Water Resource Board	Roger Chase
Northwest Power and Conservation Council	Ben Kujala
Oil and Gas Industry Advisor	David Hawk
Oregon State University—Malheur Experiment Station	Clint Shock
Snake River Alliance	Chad Worth
Regulatory Commission Representatives	
Idaho Public Utilities Commission	Stacey Donohue
Public Utility Commission of Oregon	Nadine Hanhan

IRP Advisory Council Meeting Schedule and Agenda

Meeting Dates		Agenda Items
2018	Thursday, September 13	Welcome and opening remarks 2017 IRP Review IRP overview and process road map Carbon Outlook Natural gas forecast
2018	Thursday, October 11	IRP process review Load forecast Streamflow forecast Hydro production forecast Hydro climate change modeling results PURPA forecast and assumptions Natural gas price
2018	Thursday, November 8	Regional transmission overview Boardman to Hemingway transmission update Storage outlook Resource cost assumptions IPC planning criteria capacity, energy, and flexibility—2017 IRP to 2019 IRP Coal unit futures
2018	Thursday, December 13	AURORA model workshop Energy efficiency potential study Regional resource adequacy Solar capacity credit Distributed resources: value to the transmission and distribution system
2019	Thursday, January 10	T&D deferral benefit Demand response Energy imbalance market (EIM) Reserve requirements Capacity expansion modeling update Updated resource cost assumptions
2019	Thursday, March 14	AURORA LTCE portfolio results Sensitivities to planning assumptions Stochastic elements Hells Canyon Complex relicensing Cloud seeding
2019	Thursday, April 11	Idaho Power clean energy goal AURORA results update Qualitative risk assessment Preliminary preferred portfolio recommendation
2019	Thursday, May 9	Loss of load analysis Power system operations: summer readiness IPC sustainability programs 2019 IRP action plan

Sales and Load Forecast Data

50th Percentile Annual Forecast Growth Rates

	2019–2024	2019–2029	2019–2038
Sales			
Residential Sales	1.17%	1.15%	1.13%
Commercial Sales	1.17%	1.21%	1.15%
Irrigation Sales	0.78%	0.76%	0.75%
Industrial Sales	1.09%	0.82%	0.56%
Additional Firm Sales	3.68%	2.06%	1.18%
System Sales	1.27%	1.12%	1.00%
Total Sales	1.27%	1.12%	1.00%
Loads			
Residential Load	1.11%	1.15%	1.13%
Commercial Load	1.12%	1.21%	1.14%
Irrigation Load	0.72%	0.76%	0.75%
Industrial Load	1.02%	0.81%	0.55%
Additional Firm Sales	3.68%	2.06%	1.18%
System Load Losses	1.12%	1.10%	1.02%
System Load	1.21%	1.12%	1.00%
Total Load	1.21%	1.12%	1.00%
Peaks			
System Peak	1.35%	1.27%	1.18%
Total Peak	1.35%	1.27%	1.18%
Winter Peak	1.14%	1.03%	0.95%
Summer Peak	1.35%	1.27%	1.18%
Customers			
Residential Customers	2.12%	1.93%	1.68%
Commercial Customers	1.97%	1.80%	1.67%
Irrigation Customers	1.32%	1.28%	1.21%
Industrial Customers	0.53%	0.43%	0.49%

Expected-Case Load Forecast

2019 Monthly Summary[1]	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Load (aMW) 50th Percentile												
Residential	831	711	575	502	442	530	649	605	474	487	625	786
Commercial	505	482	443	429	437	482	501	509	463	454	462	513
Irrigation	3	3	8	119	324	624	631	546	316	67	5	3
Industrial	274	280	281	270	274	294	288	296	288	291	283	282
Additional Firm	114	114	108	104	104	95	105	107	111	112	118	120
Loss	147	134	117	119	134	176	190	179	139	116	124	144
System Load	**1,874**	**1,724**	**1,532**	**1,543**	**1,714**	**2,201**	**2,363**	**2,243**	**1,791**	**1,527**	**1,617**	**1,848**
Light Load	1,750	1,587	1,406	1,398	1,558	1,991	2,133	1,986	1,616	1,368	1,489	1,712
Heavy Load	1,972	1,826	1,631	1,648	1,837	2,369	2,545	2,429	1,945	1,642	1,720	1,966
Total Load	**1,874**	**1,724**	**1,532**	**1,543**	**1,714**	**2,201**	**2,363**	**2,243**	**1,791**	**1,527**	**1,617**	**1,848**
Peak Load (MW)												
System Peak Load (1 hour) 90th Percentile	2,502	2,277	2,030	2,000	2,675	3,470	3,610	3,354	2,795	2,070	2,277	2,549
System Peak Load (1 hour) 95th Percentile	2,535	2,361	2,075	2,015	2,695	3,511	3,634	3,391	2,812	2,087	2,319	2,636

2020 Monthly Summary	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Load (aMW) 50th Percentile												
Residential	842	695	581	506	445	535	657	613	478	490	629	794
Commercial	513	472	448	434	442	488	508	516	469	459	467	518
Irrigation	3	2	8	120	328	630	638	551	319	68	5	3
Industrial	278	274	284	273	277	298	292	300	292	294	287	287
Additional Firm	117	112	110	106	106	97	106	109	113	114	120	123
Loss	149	131	119	120	135	178	192	181	141	117	125	146
System Load	**1,901**	**1,687**	**1,549**	**1,560**	**1,733**	**2,226**	**2,393**	**2,271**	**1,810**	**1,542**	**1,633**	**1,871**
Light Load	1,775	1,553	1,422	1,414	1,575	2,013	2,160	2,011	1,633	1,382	1,504	1,733
Heavy Load	2,000	1,785	1,649	1,667	1,869	2,381	2,577	2,476	1,952	1,658	1,747	1,980
Total Load	**1,901**	**1,687**	**1,549**	**1,560**	**1,733**	**2,226**	**2,393**	**2,271**	**1,810**	**1,542**	**1,633**	**1,871**
Peak Load (MW)												
System Peak Load (1 hour) 90th Percentile	2,522	2,298	2,034	2,017	2,693	3,527	3,659	3,407	2,829	2,087	2,295	2,581
System Peak Load (1 hour) 95th Percentile	2,555	2,382	2,080	2,032	2,713	3,568	3,683	3,444	2,846	2,105	2,337	2,668

[1] The sales and load forecast considers and reflects the impact of existing energy efficiency programs on average load and peak demand. The new energy efficiency programs, proposed as part of the 2017 IRP, are accounted for in the load and resource balance. The peak load forecast does not include the impact of existing or new demand response programs, which are both accounted for in the load and resource balance.

2021 Monthly Summary	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Load (aMW) 50th Percentile												
Residential	853	730	586	510	448	540	665	620	481	492	633	802
Commercial	518	493	451	439	446	493	513	522	473	462	471	524
Irrigation	3	3	8	121	330	634	642	555	321	68	5	3
Industrial	282	288	288	277	281	302	296	304	296	299	291	289
Additional Firm	121	120	114	110	110	101	111	113	117	119	125	127
Loss	151	137	120	121	136	180	194	183	142	118	126	148
System Load	**1,928**	**1,771**	**1,567**	**1,577**	**1,751**	**2,249**	**2,421**	**2,298**	**1,829**	**1,558**	**1,651**	**1,893**
Light Load	1,801	1,631	1,439	1,430	1,592	2,034	2,185	2,035	1,650	1,396	1,520	1,754
Heavy Load	2,038	1,876	1,660	1,685	1,888	2,406	2,607	2,506	1,973	1,686	1,756	2,004
Total Load	**1,928**	**1,771**	**1,567**	**1,577**	**1,751**	**2,249**	**2,421**	**2,298**	**1,829**	**1,558**	**1,651**	**1,893**
Peak Load (MW)												
System Peak Load (1 hour) 90th Percentile	2,555	2,322	2,060	2,032	2,710	3,558	3,707	3,450	2,860	2,105	2,312	2,597
System Peak Load (1 hour) 95th Percentile	2,588	2,406	2,106	2,047	2,730	3,600	3,731	3,487	2,877	2,123	2,354	2,684

2022 Monthly Summary	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Load (aMW) 50th Percentile												
Residential	864	738	590	513	451	545	674	629	486	496	639	812
Commercial	527	500	457	445	452	499	521	530	478	468	477	531
Irrigation	3	3	8	122	333	640	647	560	324	69	5	3
Industrial	284	290	291	280	283	305	299	307	298	301	293	292
Additional Firm	125	124	118	114	114	105	114	117	121	123	129	131
Loss	153	139	121	123	138	182	197	185	144	120	128	149
System Load	**1,956**	**1,795**	**1,585**	**1,595**	**1,770**	**2,275**	**2,453**	**2,329**	**1,852**	**1,577**	**1,671**	**1,919**
Light Load	1,826	1,653	1,455	1,446	1,609	2,058	2,214	2,062	1,670	1,413	1,538	1,777
Heavy Load	2,067	1,901	1,679	1,704	1,909	2,434	2,659	2,522	1,997	1,706	1,778	2,031
Total Load	**1,956**	**1,795**	**1,585**	**1,595**	**1,770**	**2,275**	**2,453**	**2,329**	**1,852**	**1,577**	**1,671**	**1,919**
Peak Load (MW)												
System Peak Load (1 hour) 90th Percentile	2,554	2,346	2,080	2,048	2,728	3,609	3,757	3,506	2,897	2,125	2,332	2,625
System Peak Load (1 hour) 95th Percentile	2,617	2,430	2,125	2,063	2,749	3,650	3,782	3,544	2,914	2,143	2,374	2,712

2023 Monthly Summary	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Load (aMW) 50th Percentile												
Residential	878	749	598	519	457	554	687	640	492	501	646	822
Commercial	534	506	462	450	457	505	528	537	483	473	482	537
Irrigation	3	3	8	123	336	645	653	565	326	69	5	3
Industrial	287	293	293	282	286	308	302	310	301	304	296	295
Additional Firm	127	126	120	116	116	107	117	120	124	125	131	134
Loss	156	141	123	124	139	184	199	188	145	121	129	151
System Load	**1,984**	**1,819**	**1,604**	**1,614**	**1,791**	**2,302**	**2,485**	**2,359**	**1,872**	**1,593**	**1,689**	**1,942**
Light Load	1,852	1,675	1,472	1,463	1,627	2,083	2,243	2,089	1,689	1,428	1,555	1,799
Heavy Load	2,097	1,927	1,699	1,735	1,919	2,463	2,693	2,555	2,019	1,724	1,797	2,065
Total Load	**1,984**	**1,819**	**1,604**	**1,614**	**1,791**	**2,302**	**2,485**	**2,359**	**1,872**	**1,593**	**1,689**	**1,942**
Peak Load (MW)												
System Peak Load (1 hour) 90th Percentile	2,611	2,369	2,097	2,064	2,747	3,654	3,808	3,559	2,932	2,144	2,350	2,648
System Peak Load (1 hour) 95th Percentile	2,644	2,453	2,143	2,079	2,767	3,696	3,832	3,596	2,949	2,161	2,392	2,735

2024 Monthly Summary	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Load (aMW) 50th Percentile												
Residential	891	734	605	525	462	562	698	650	498	505	652	832
Commercial	540	494	466	455	461	510	534	544	488	477	486	543
Irrigation	3	3	8	124	338	650	658	569	329	70	5	3
Industrial	290	286	296	285	289	311	304	313	304	307	299	297
Additional Firm	138	132	130	124	124	115	124	127	131	134	141	145
Loss	158	138	124	126	141	186	202	190	147	122	131	153
System Load	**2,020**	**1,787**	**1,629**	**1,638**	**1,815**	**2,334**	**2,521**	**2,393**	**1,897**	**1,615**	**1,714**	**1,973**
Light Load	1,886	1,646	1,495	1,484	1,650	2,111	2,275	2,119	1,711	1,447	1,578	1,827
Heavy Load	2,125	1,892	1,735	1,750	1,945	2,512	2,715	2,592	2,059	1,736	1,824	2,098
Total Load	**2,020**	**1,787**	**1,629**	**1,638**	**1,815**	**2,334**	**2,521**	**2,393**	**1,897**	**1,615**	**1,714**	**1,973**
Peak Load (MW)												
System Peak Load (1 hour) 90th Percentile	2,650	2,400	2,125	2,087	2,771	3,706	3,863	3,617	2,971	2,167	2,376	2,682
System Peak Load (1 hour) 95th Percentile	2,683	2,484	2,171	2,102	2,791	3,748	3,887	3,655	2,988	2,185	2,418	2,768

2025 Monthly Summary	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Load (aMW) 50th Percentile												
Residential	903	771	611	530	467	569	710	660	503	509	657	840
Commercial	548	519	472	461	467	517	541	551	493	482	492	550
Irrigation	3	3	8	125	341	655	663	573	331	70	5	3
Industrial	292	298	298	287	291	313	307	315	306	309	301	298
Additional Firm	140	139	132	126	125	116	125	128	132	135	143	147
Loss	160	145	125	127	142	188	204	192	148	123	132	155
System Load	**2,047**	**1,875**	**1,646**	**1,654**	**1,833**	**2,358**	**2,550**	**2,421**	**1,915**	**1,629**	**1,731**	**1,993**
Light Load	1,911	1,727	1,511	1,499	1,666	2,133	2,302	2,144	1,727	1,460	1,593	1,846
Heavy Load	2,154	1,986	1,753	1,768	1,965	2,538	2,746	2,640	2,065	1,752	1,851	2,109
Total Load	**2,047**	**1,875**	**1,646**	**1,654**	**1,833**	**2,358**	**2,550**	**2,421**	**1,915**	**1,629**	**1,731**	**1,993**
Peak Load (MW)												
System Peak Load (1 hour) 90th Percentile	2,679	2,426	2,144	2,101	2,787	3,753	3,911	3,670	3,003	2,184	2,392	2,705
System Peak Load (1 hour) 95th Percentile	2,711	2,510	2,190	2,116	2,808	3,795	3,935	3,707	3,020	2,201	2,435	2,791

2026 Monthly Summary	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Load (aMW) 50th Percentile												
Residential	914	779	616	534	471	575	719	669	507	511	661	847
Commercial	556	526	477	466	472	523	549	559	499	487	497	556
Irrigation	3	3	8	126	343	660	668	578	334	71	5	3
Industrial	293	300	300	288	292	315	308	317	308	311	303	300
Additional Firm	141	140	132	126	126	117	126	129	133	136	144	148
Loss	162	147	126	128	144	190	207	195	150	124	133	156
System Load	**2,069**	**1,893**	**1,660**	**1,668**	**1,848**	**2,380**	**2,577**	**2,446**	**1,930**	**1,641**	**1,743**	**2,011**
Light Load	1,932	1,744	1,523	1,512	1,680	2,152	2,325	2,165	1,741	1,470	1,605	1,862
Heavy Load	2,177	2,006	1,767	1,782	1,993	2,545	2,775	2,667	2,082	1,764	1,865	2,128
Total Load	**2,069**	**1,893**	**1,660**	**1,668**	**1,848**	**2,380**	**2,577**	**2,446**	**1,930**	**1,641**	**1,743**	**2,011**
Peak Load (MW)												
System Peak Load (1 hour) 90th Percentile	2,699	2,443	2,154	2,113	2,801	3,786	3,956	3,712	3,030	2,196	2,404	2,717
System Peak Load (1 hour) 95th Percentile	2,732	2,527	2,200	2,128	2,821	3,827	3,980	3,749	3,047	2,214	2,446	2,804

2027 Monthly Summary	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Load (aMW) 50th Percentile												
Residential	924	787	621	537	474	581	728	677	511	513	664	856
Commercial	564	532	482	472	477	529	556	567	504	492	503	563
Irrigation	3	3	8	127	346	666	674	583	337	72	5	3
Industrial	295	301	302	290	294	317	310	319	310	313	305	302
Additional Firm	141	140	132	126	126	117	126	129	133	136	144	148
Loss	164	148	128	129	145	191	209	197	151	125	134	158
System Load	**2,091**	**1,912**	**1,673**	**1,681**	**1,863**	**2,401**	**2,603**	**2,470**	**1,945**	**1,651**	**1,755**	**2,030**
Light Load	1,952	1,761	1,535	1,524	1,693	2,172	2,349	2,187	1,755	1,480	1,616	1,880
Heavy Load	2,210	2,025	1,772	1,796	2,009	2,568	2,803	2,693	2,098	1,787	1,867	2,148
Total Load	**2,091**	**1,912**	**1,673**	**1,681**	**1,863**	**2,401**	**2,603**	**2,470**	**1,945**	**1,651**	**1,755**	**2,030**
Peak Load (MW)												
System Peak Load (1 hour) 90th Percentile	2,721	2,460	2,166	2,124	2,814	3,826	4,001	3,759	3,057	2,208	2,416	2,736
System Peak Load (1 hour) 95th Percentile	2,753	2,544	2,212	2,139	2,835	3,867	4,026	3,796	3,074	2,226	2,458	2,823

2028 Monthly Summary	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Load (aMW) 50th Percentile												
Residential	937	771	627	542	479	588	740	687	516	517	670	866
Commercial	572	520	487	478	483	536	564	575	510	498	508	570
Irrigation	3	3	9	128	349	671	679	587	339	72	5	3
Industrial	297	292	303	292	295	318	312	320	311	314	306	303
Additional Firm	141	136	133	127	126	117	126	129	134	136	145	148
Loss	166	145	129	130	146	193	211	199	152	126	135	160
System Load	**2,116**	**1,866**	**1,688**	**1,696**	**1,879**	**2,424**	**2,631**	**2,497**	**1,962**	**1,664**	**1,769**	**2,051**
Light Load	1,976	1,719	1,549	1,537	1,708	2,192	2,375	2,211	1,770	1,491	1,629	1,900
Heavy Load	2,236	1,976	1,788	1,823	2,014	2,593	2,852	2,704	2,116	1,800	1,882	2,181
Total Load	**2,116**	**1,866**	**1,688**	**1,696**	**1,879**	**2,424**	**2,631**	**2,497**	**1,962**	**1,664**	**1,769**	**2,051**
Peak Load (MW)												
System Peak Load (1 hour) 90th Percentile	2,747	2,480	2,183	2,137	2,829	3,874	4,048	3,812	3,087	2,222	2,430	2,761
System Peak Load (1 hour) 95th Percentile	2,780	2,564	2,229	2,152	2,849	3,916	4,073	3,849	3,104	2,240	2,472	2,848

2029 Monthly Summary	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Load (aMW) 50th Percentile												
Residential	952	810	635	548	484	597	752	698	522	522	676	875
Commercial	581	546	493	484	489	543	572	583	516	503	514	578
Irrigation	3	3	9	129	352	676	684	592	342	73	5	3
Industrial	298	304	304	293	297	319	313	322	313	316	307	304
Additional Firm	142	141	133	127	127	118	127	130	134	137	145	149
Loss	168	152	130	132	147	195	214	201	154	127	136	161
System Load	**2,143**	**1,956**	**1,704**	**1,712**	**1,896**	**2,448**	**2,662**	**2,525**	**1,980**	**1,677**	**1,784**	**2,071**
Light Load	2,001	1,802	1,564	1,552	1,723	2,214	2,402	2,236	1,786	1,503	1,643	1,918
Heavy Load	2,255	2,072	1,805	1,840	2,032	2,618	2,885	2,734	2,150	1,803	1,898	2,202
Total Load	**2,143**	**1,956**	**1,704**	**1,712**	**1,896**	**2,448**	**2,662**	**2,525**	**1,980**	**1,677**	**1,784**	**2,071**
Peak Load (MW)												
System Peak Load (1 hour) 90th Percentile	2,777	2,505	2,203	2,151	2,844	3,928	4,097	3,869	3,119	2,237	2,444	2,786
System Peak Load (1 hour) 95th Percentile	2,809	2,589	2,249	2,166	2,865	3,970	4,121	3,906	3,136	2,255	2,487	2,873

2030 Monthly Summary	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Load (aMW) 50th Percentile												
Residential	963	820	640	552	488	602	762	706	526	524	680	884
Commercial	590	554	499	491	495	550	580	592	522	509	521	585
Irrigation	3	3	9	130	355	682	690	597	345	73	5	3
Industrial	299	305	305	294	298	320	314	323	314	317	308	305
Additional Firm	142	141	133	127	127	118	127	130	134	137	145	149
Loss	170	154	131	133	149	197	216	203	155	128	137	163
System Load	**2,167**	**1,976**	**1,718**	**1,726**	**1,911**	**2,469**	**2,689**	**2,551**	**1,995**	**1,688**	**1,797**	**2,089**
Light Load	2,023	1,820	1,576	1,564	1,737	2,234	2,427	2,258	1,800	1,513	1,654	1,935
Heavy Load	2,280	2,093	1,829	1,844	2,048	2,658	2,895	2,762	2,167	1,815	1,912	2,222
Total Load	**2,167**	**1,976**	**1,718**	**1,726**	**1,911**	**2,469**	**2,689**	**2,551**	**1,995**	**1,688**	**1,797**	**2,089**
Peak Load (MW)												
System Peak Load (1 hour) 90th Percentile	2,799	2,524	2,215	2,163	2,858	3,966	4,143	3,915	3,147	2,250	2,457	2,803
System Peak Load (1 hour) 95th Percentile	2,832	2,608	2,261	2,178	2,878	4,008	4,167	3,953	3,164	2,268	2,499	2,890

2031 Monthly Summary	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Load (aMW) 50th Percentile												
Residential	975	829	645	555	491	608	772	715	530	526	684	892
Commercial	598	561	505	497	501	556	588	600	528	515	526	593
Irrigation	3	3	9	131	357	687	695	601	347	74	5	3
Industrial	300	306	307	295	299	322	315	324	315	318	310	306
Additional Firm	142	141	134	128	127	118	127	130	134	137	145	149
Loss	172	155	132	134	150	199	218	205	156	129	138	164
System Load	**2,191**	**1,996**	**1,731**	**1,739**	**1,925**	**2,490**	**2,716**	**2,576**	**2,011**	**1,699**	**1,809**	**2,108**
Light Load	2,046	1,838	1,589	1,576	1,750	2,253	2,451	2,281	1,814	1,523	1,666	1,952
Heavy Load	2,295	2,114	1,843	1,858	2,052	2,681	2,907	2,809	2,155	1,827	1,925	2,220
Total Load	**2,191**	**1,996**	**1,731**	**1,739**	**1,925**	**2,490**	**2,716**	**2,576**	**2,011**	**1,699**	**1,809**	**2,108**
Peak Load (MW)												
System Peak Load (1 hour) 90th Percentile	2,826	2,545	2,233	2,174	2,871	4,019	4,189	3,971	3,174	2,262	2,469	2,828
System Peak Load (1 hour) 95th Percentile	2,859	2,629	2,278	2,189	2,892	4,060	4,213	4,008	3,191	2,280	2,511	2,915

2032 Monthly Summary	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Load (aMW) 50th Percentile												
Residential	987	810	650	559	495	614	782	724	534	529	688	899
Commercial	607	549	510	503	507	563	596	608	534	520	532	599
Irrigation	3	3	9	132	360	692	700	606	350	74	5	3
Industrial	301	297	308	296	300	323	316	325	316	319	311	307
Additional Firm	142	137	134	128	127	118	127	130	135	138	146	150
Loss	174	151	133	135	151	201	221	208	158	130	139	166
System Load	**2,214**	**1,946**	**1,744**	**1,752**	**1,940**	**2,511**	**2,742**	**2,601**	**2,026**	**1,710**	**1,821**	**2,124**
Light Load	2,068	1,792	1,601	1,588	1,763	2,271	2,475	2,303	1,827	1,532	1,677	1,967
Heavy Load	2,320	2,071	1,847	1,872	2,079	2,686	2,935	2,836	2,171	1,850	1,927	2,237
Total Load	**2,214**	**1,946**	**1,744**	**1,752**	**1,940**	**2,511**	**2,742**	**2,601**	**2,026**	**1,710**	**1,821**	**2,124**
Peak Load (MW)												
System Peak Load (1 hour) 90th Percentile	2,849	2,559	2,245	2,185	2,884	4,057	4,234	4,017	3,201	2,274	2,480	2,844
System Peak Load (1 hour) 95th Percentile	2,882	2,644	2,290	2,200	2,905	4,099	4,258	4,054	3,218	2,292	2,522	2,930

2033 Monthly Summary	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Load (aMW) 50th Percentile												
Residential	996	846	653	560	496	618	790	731	536	529	690	906
Commercial	615	575	515	509	512	569	603	616	539	525	538	606
Irrigation	3	3	9	133	363	697	706	610	353	75	5	3
Industrial	302	308	309	297	301	324	317	326	317	320	312	308
Additional Firm	143	142	134	128	128	119	128	131	135	138	146	150
Loss	176	158	134	136	152	202	223	209	159	130	140	167
System Load	**2,235**	**2,032**	**1,755**	**1,762**	**1,952**	**2,529**	**2,766**	**2,624**	**2,038**	**1,718**	**1,831**	**2,140**
Light Load	2,087	1,872	1,610	1,597	1,774	2,288	2,496	2,323	1,839	1,539	1,685	1,982
Heavy Load	2,352	2,153	1,859	1,883	2,092	2,706	2,979	2,841	2,184	1,859	1,937	2,254
Total Load	**2,235**	**2,032**	**1,755**	**1,762**	**1,952**	**2,529**	**2,766**	**2,624**	**2,038**	**1,718**	**1,831**	**2,140**
Peak Load (MW)												
System Peak Load (1 hour) 90th Percentile	2,870	2,579	2,255	2,195	2,895	4,096	4,277	4,062	3,224	2,283	2,489	2,860
System Peak Load (1 hour) 95th Percentile	2,902	2,664	2,301	2,210	2,916	4,137	4,301	4,099	3,241	2,301	2,532	2,947

2034 Monthly Summary	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Load (aMW) 50th Percentile												
Residential	1,008	856	659	564	501	625	801	741	541	533	695	916
Commercial	622	581	520	514	517	575	610	623	544	530	542	612
Irrigation	3	3	9	134	365	703	711	615	355	76	5	3
Industrial	303	309	310	298	302	325	318	327	318	321	313	309
Additional Firm	143	142	134	128	128	119	128	131	135	138	146	150
Loss	178	160	135	137	153	204	225	212	160	131	141	169
System Load	**2,257**	**2,051**	**1,767**	**1,775**	**1,966**	**2,551**	**2,794**	**2,650**	**2,054**	**1,729**	**1,844**	**2,159**
Light Load	2,108	1,889	1,622	1,609	1,787	2,307	2,522	2,346	1,853	1,549	1,697	1,999
Heavy Load	2,375	2,172	1,871	1,908	2,095	2,729	3,009	2,869	2,201	1,871	1,951	2,284
Total Load	**2,257**	**2,051**	**1,767**	**1,775**	**1,966**	**2,551**	**2,794**	**2,650**	**2,054**	**1,729**	**1,844**	**2,159**
Peak Load (MW)												
System Peak Load (1 hour) 90th Percentile	2,893	2,598	2,269	2,205	2,908	4,142	4,324	4,114	3,252	2,296	2,502	2,882
System Peak Load (1 hour) 95th Percentile	2,926	2,682	2,315	2,220	2,928	4,184	4,348	4,151	3,269	2,314	2,544	2,969

2035 Monthly Summary	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Load (aMW) 50th Percentile												
Residential	1,022	868	667	571	507	635	816	754	548	538	702	927
Commercial	630	587	525	519	521	581	617	630	549	534	547	618
Irrigation	3	3	9	135	368	708	717	620	358	76	6	3
Industrial	304	310	310	299	303	326	319	328	319	322	313	309
Additional Firm	143	142	135	129	128	119	128	131	136	139	147	150
Loss	180	162	136	138	155	206	227	214	161	132	142	170
System Load	**2,282**	**2,072**	**1,781**	**1,790**	**1,982**	**2,575**	**2,824**	**2,678**	**2,070**	**1,741**	**1,857**	**2,178**
Light Load	2,131	1,908	1,635	1,622	1,802	2,329	2,549	2,371	1,868	1,560	1,709	2,017
Heavy Load	2,391	2,194	1,887	1,924	2,113	2,755	3,041	2,899	2,233	1,872	1,965	2,305
Total Load	**2,282**	**2,072**	**1,781**	**1,790**	**1,982**	**2,575**	**2,824**	**2,678**	**2,070**	**1,741**	**1,857**	**2,178**
Peak Load (MW)												
System Peak Load (1 hour) 90th Percentile	2,919	2,619	2,286	2,218	2,923	4,192	4,372	4,168	3,281	2,309	2,515	2,905
System Peak Load (1 hour) 95th Percentile	2,952	2,703	2,331	2,233	2,943	4,233	4,397	4,206	3,298	2,327	2,557	2,992

2036 Monthly Summary	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Load (aMW) 50th Percentile												
Residential	1,038	851	675	579	514	646	832	768	555	543	709	938
Commercial	637	572	529	524	526	586	624	637	553	538	552	624
Irrigation	3	3	9	136	371	714	722	625	361	77	6	3
Industrial	304	300	311	299	303	326	320	329	319	322	314	310
Additional Firm	144	138	135	129	129	120	129	132	136	139	147	151
Loss	182	158	138	139	156	208	230	216	163	133	143	172
System Load	**2,308**	**2,021**	**1,797**	**1,806**	**2,000**	**2,600**	**2,856**	**2,706**	**2,088**	**1,753**	**1,870**	**2,198**
Light Load	2,155	1,862	1,649	1,637	1,817	2,352	2,577	2,396	1,883	1,570	1,722	2,036
Heavy Load	2,418	2,139	1,913	1,929	2,131	2,798	3,057	2,951	2,237	1,884	1,990	2,315
Total Load	**2,308**	**2,021**	**1,797**	**1,806**	**2,000**	**2,600**	**2,856**	**2,706**	**2,088**	**1,753**	**1,870**	**2,198**
Peak Load (MW)												
System Peak Load (1 hour) 90th Percentile	2,948	2,638	2,304	2,232	2,939	4,247	4,422	4,226	3,312	2,322	2,528	2,931
System Peak Load (1 hour) 95th Percentile	2,980	2,722	2,350	2,247	2,959	4,288	4,446	4,264	3,329	2,340	2,570	3,018

2037 Monthly Summary	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Load (aMW) 50th Percentile												
Residential	1,053	894	684	586	522	657	847	781	563	548	716	949
Commercial	644	599	533	529	531	591	630	644	557	542	556	629
Irrigation	3	3	9	137	374	719	728	630	364	77	6	3
Industrial	305	311	311	300	304	327	320	329	320	323	314	310
Additional Firm	144	143	135	129	129	120	129	132	136	139	147	151
Loss	184	165	139	141	158	210	233	219	164	134	145	173
System Load	**2,333**	**2,115**	**1,811**	**1,821**	**2,016**	**2,624**	**2,887**	**2,735**	**2,104**	**1,764**	**1,883**	**2,216**
Light Load	2,179	1,948	1,662	1,650	1,833	2,374	2,605	2,421	1,898	1,581	1,734	2,052
Heavy Load	2,445	2,240	1,928	1,945	2,161	2,807	3,090	2,982	2,255	1,897	2,004	2,334
Total Load	**2,333**	**2,115**	**1,811**	**1,821**	**2,016**	**2,624**	**2,887**	**2,735**	**2,104**	**1,764**	**1,883**	**2,216**
Peak Load (MW)												
System Peak Load (1 hour) 90th Percentile	2,974	2,662	2,320	2,245	2,954	4,295	4,471	4,280	3,341	2,335	2,540	2,951
System Peak Load (1 hour) 95th Percentile	3,006	2,747	2,366	2,260	2,974	4,336	4,495	4,317	3,358	2,353	2,583	3,038

2038 Monthly Summary	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average Load (aMW) 50th Percentile												
Residential	1,068	906	691	593	528	667	862	794	569	553	722	959
Commercial	650	604	537	533	534	596	636	650	561	546	560	633
Irrigation	3	3	9	138	377	725	734	635	367	78	6	4
Industrial	305	311	312	300	304	327	321	330	320	323	315	311
Additional Firm	144	143	135	129	129	120	129	132	137	140	148	151
Loss	186	167	140	142	159	212	235	221	165	135	146	175
System Load	**2,357**	**2,134**	**1,825**	**1,835**	**2,032**	**2,647**	**2,917**	**2,762**	**2,119**	**1,774**	**1,895**	**2,233**
Light Load	2,201	1,966	1,675	1,663	1,847	2,395	2,632	2,445	1,912	1,590	1,744	2,069
Heavy Load	2,480	2,261	1,933	1,960	2,178	2,832	3,122	3,011	2,271	1,920	2,005	2,352
Total Load	**2,357**	**2,134**	**1,825**	**1,835**	**2,032**	**2,647**	**2,917**	**2,762**	**2,119**	**1,774**	**1,895**	**2,233**
Peak Load (MW)												
System Peak Load (1 hour) 90th Percentile	2,998	2,682	2,334	2,257	2,968	4,341	4,519	4,332	3,369	2,347	2,552	2,971
System Peak Load (1 hour) 95th Percentile	3,031	2,766	2,380	2,272	2,988	4,382	4,544	4,369	3,386	2,364	2,594	3,058

Annual Summary

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Billed Sales (MWh) 70th Percentile										
Residential	5,437,937	5,493,644	5,547,973	5,608,333	5,688,441	5,763,194	5,834,023	5,890,805	5,944,148	6,014,532
Commercial	4,196,788	4,251,251	4,291,921	4,350,949	4,401,332	4,448,900	4,505,483	4,562,301	4,615,732	4,674,083
Irrigation	2,074,146	2,093,175	2,106,818	2,123,833	2,140,578	2,156,322	2,171,522	2,187,603	2,204,350	2,221,073
Industrial	2,481,792	2,510,977	2,547,534	2,570,263	2,595,285	2,619,587	2,638,463	2,652,628	2,669,207	2,681,291
Additional Firm	956,699	977,000	1,013,000	1,048,000	1,069,000	1,146,000	1,161,000	1,164,000	1,167,000	1,171,000
System Load	15,147,362	15,326,046	15,507,246	15,701,378	15,894,635	16,134,002	16,310,491	16,457,337	16,600,437	16,761,979
Total Load	**15,147,362**	**15,326,046**	**15,507,246**	**15,701,378**	**15,894,635**	**16,134,002**	**16,310,491**	**16,457,337**	**16,600,437**	**16,761,979**
Generation Month Sales (MWh) 70th Percentile										
Residential	5,442,618	5,498,804	5,552,533	5,614,209	5,693,977	5,768,505	5,838,363	5,894,961	5,949,634	6,020,876
Commercial	4,200,298	4,253,908	4,295,719	4,354,214	4,404,424	4,452,555	4,509,159	4,565,769	4,619,509	4,678,039
Irrigation	2,074,158	2,093,183	2,106,828	2,123,843	2,140,588	2,156,331	2,171,532	2,187,613	2,204,360	2,221,083
Industrial	2,484,235	2,514,036	2,549,437	2,572,357	2,597,319	2,621,167	2,639,649	2,654,015	2,670,219	2,682,204
Additional Firm	956,699	977,000	1,013,000	1,048,000	1,069,000	1,146,000	1,161,000	1,164,000	1,167,000	1,171,000
System Sales	**15,158,009**	**15,336,932**	**15,517,517**	**15,712,623**	**15,905,307**	**16,144,558**	**16,319,702**	**16,466,359**	**16,610,723**	**16,773,202**
Total Sales	**15,158,009**	**15,336,932**	**15,517,517**	**15,712,623**	**15,905,307**	**16,144,558**	**16,319,702**	**16,466,359**	**16,610,723**	**16,773,202**
Loss	1,290,909	1,305,542	1,319,389	1,335,058	1,351,249	1,368,458	1,383,403	1,396,552	1,409,433	1,424,125
Required Generation	**16,448,918**	**16,642,475**	**16,836,907**	**17,047,681**	**17,256,557**	**17,513,016**	**17,703,106**	**17,862,910**	**18,020,155**	**18,197,327**
Average Load (aMW) 70th Percentile										
Residential	621	626	634	641	650	657	666	673	679	685
Commercial	479	484	490	497	503	507	515	521	527	533
Irrigation	237	238	241	242	244	245	248	250	252	253
Industrial	284	286	291	294	296	298	301	303	305	305
Additional Firm	109	111	116	120	122	130	133	133	133	133
Loss	147	149	151	152	154	156	158	159	161	162
System Load	**1,878**	**1,895**	**1,922**	**1,946**	**1,970**	**1,994**	**2,021**	**2,039**	**2,057**	**2,072**
Light Load	1,708	1,723	1,748	1,770	1,792	1,814	1,838	1,855	1,871	1,885
Heavy Load	2,010	2,029	2,058	2,084	2,110	2,134	2,164	2,183	2,203	2,219
Total Load	**1,878**	**1,895**	**1,922**	**1,946**	**1,970**	**1,994**	**2,021**	**2,039**	**2,057**	**2,072**
Peak Load (MW) 95th Percentile										
System Peak (1 hour)	3,634	3,683	3,731	3,782	3,832	3,887	3,935	3,980	4,026	4,073
Total Peak Load	**3,634**	**3,683**	**3,731**	**3,782**	**3,832**	**3,887**	**3,935**	**3,980**	**4,026**	**4,073**

	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Billed Sales (MWh) 70th Percentile										
Residential	6,095,509	6,152,545	6,212,850	6,269,841	6,312,160	6,378,952	6,464,432	6,557,678	6,648,731	6,734,413
Commercial	4,735,240	4,799,479	4,857,014	4,919,215	4,972,567	5,023,928	5,074,557	5,123,093	5,170,831	5,211,986
Irrigation	2,237,536	2,254,044	2,270,422	2,286,620	2,303,006	2,319,804	2,336,631	2,353,973	2,371,564	2,389,219
Industrial	2,692,197	2,700,947	2,713,441	2,720,965	2,731,480	2,739,017	2,745,330	2,750,321	2,754,092	2,758,211
Additional Firm	1,173,000	1,176,000	1,178,000	1,180,000	1,183,000	1,186,000	1,188,000	1,191,000	1,193,000	1,196,000
System Load	**16,933,481**	**17,083,016**	**17,231,727**	**17,376,641**	**17,502,212**	**17,647,701**	**17,808,951**	**17,976,065**	**18,138,217**	**18,289,829**
Total Load	**16,933,481**	**17,083,016**	**17,231,727**	**17,376,641**	**17,502,212**	**17,647,701**	**17,808,951**	**17,976,065**	**18,138,217**	**18,289,829**
Generation Month Sales (MWh) 70th Percentile										
Residential	6,100,167	6,157,528	6,217,678	6,273,685	6,316,791	6,384,855	6,470,892	6,563,965	6,654,615	6,740,060
Commercial	4,739,391	4,803,216	4,861,046	4,922,698	4,975,928	5,027,246	5,077,747	5,126,236	5,173,564	5,214,450
Irrigation	2,237,546	2,254,054	2,270,432	2,286,630	2,303,016	2,319,814	2,336,642	2,353,984	2,371,575	2,389,230
Industrial	2,692,929	2,701,993	2,714,070	2,721,845	2,732,111	2,739,546	2,745,748	2,750,637	2,754,437	2,758,943
Additional Firm	1,173,000	1,176,000	1,178,000	1,180,000	1,183,000	1,186,000	1,188,000	1,191,000	1,193,000	1,196,000
System Sales	**16,943,033**	**17,092,792**	**17,241,226**	**17,384,857**	**17,510,845**	**17,657,460**	**17,819,029**	**17,985,821**	**18,147,190**	**18,298,683**
Total Sales	**16,943,033**	**17,092,792**	**17,241,226**	**17,384,857**	**17,510,845**	**17,657,460**	**17,819,029**	**17,985,821**	**18,147,190**	**18,298,683**
Loss	1,439,675	1,453,295	1,466,761	1,479,909	1,491,254	1,504,694	1,519,675	1,535,160	1,550,227	1,564,294
Required Generation	**18,382,709**	**18,546,087**	**18,707,987**	**18,864,766**	**19,002,100**	**19,162,154**	**19,338,704**	**19,520,980**	**19,697,417**	**19,862,977**
Average Load (aMW) 70th Percentile										
Residential	696	703	710	714	721	729	739	747	760	769
Commercial	541	548	555	560	568	574	580	584	591	595
Irrigation	255	257	259	260	263	265	267	268	271	273
Industrial	307	308	310	310	312	313	313	313	314	315
Additional Firm	134	134	134	134	135	135	136	136	136	137
Loss	164	166	167	168	170	172	173	175	177	179
System Load	**2,098**	**2,117**	**2,136**	**2,148**	**2,169**	**2,187**	**2,208**	**2,222**	**2,249**	**2,267**
Light Load	1,909	1,926	1,943	1,954	1,973	1,990	2,008	2,022	2,046	2,063
Heavy Load	2,247	2,267	2,281	2,293	2,316	2,336	2,357	2,373	2,401	2,421
Total Load	**2,098**	**2,117**	**2,136**	**2,148**	**2,169**	**2,187**	**2,208**	**2,222**	**2,249**	**2,267**
Peak Load (MW) 95th Percentile										
System Peak (1 hour)	4,121	4,167	4,213	4,258	4,301	4,348	4,397	4,446	4,495	4,544
Total Peak Load	4,121	4,167	4,213	4,258	4,301	4,348	4,397	4,446	4,495	4,544

DEMAND-SIDE RESOURCE DATA

DSM Financial Assumptions

Avoided 30-Year Levelized Capacity Costs	
Reciprocating Internal Combustion Engine (RICE)	$126.72/kW-year
Financial Assumptions	
Discount rate (weighted average cost of capital)	9.59%
Financial escalation factor	2.20%
Transmission Losses	
Non-summer secondary losses	9.60%
Summer peak loss	9.70%

Avoided Cost Averages ($/MWh except where noted)

Year	Summer On-Peak[1]	Summer Mid-Peak	Summer Off-Peak	Non-Summer Mid-Peak	Non-Summer Off-Peak	Annual Average[2]	Annual T&D On-Peak Deferral Value ($/kW-year)
2019	$44.25	$31.23	$29.49	$26.68	$24.35	$42.14	$6.52
2020	$47.17	$30.37	$28.44	$27.25	$24.33	$42.35	$4.10
2021	$50.02	$32.12	$30.37	$28.34	$25.30	$43.68	$4.10
2022	$52.88	$33.05	$31.15	$28.93	$26.40	$44.62	$4.10
2023	$54.91	$33.72	$32.19	$29.45	$27.11	$45.35	$3.99
2024	$56.78	$36.21	$34.79	$31.80	$28.94	$47.47	$3.99
2025	$58.50	$37.74	$36.69	$33.34	$30.28	$49.04	$3.84
2026	$60.06	$36.09	$31.96	$34.91	$29.98	$49.15	$3.94
2027	$61.46	$38.13	$34.67	$36.96	$32.16	$51.24	$4.10
2028	$62.79	$41.00	$37.46	$38.98	$34.72	$53.49	$4.22
2029	$64.09	$44.00	$40.39	$42.07	$37.40	$56.36	$4.28
2030	$65.39	$45.86	$42.18	$43.98	$39.48	$58.26	$4.22
2031	$66.67	$48.93	$45.78	$46.99	$42.30	$61.18	$4.28
2032	$67.95	$51.24	$48.32	$49.56	$44.49	$63.49	$4.28
2033	$69.24	$53.49	$50.57	$51.55	$46.98	$65.69	$4.28
2034	$70.55	$54.78	$52.22	$51.78	$48.66	$66.69	$2.49
2035	$71.90	$56.01	$53.23	$52.88	$49.36	$67.68	$2.67
2036	$73.27	$58.33	$54.49	$54.67	$51.00	$69.36	$2.59
2037	$74.88	$60.64	$57.72	$57.12	$53.42	$71.87	$1.40
2038	$76.53	$58.81	$55.65	$56.63	$52.60	$71.11	$1.49

[1] Estimated average annual variable operations and management costs of a 111 MW-capacity RICE unit.

[2] Annual average across all hours includes avoided capacity value of $126.72 kW-year from a 111 MW RICE unit applied across Summer On-Peak hours.

Bundle Amounts

Cumulative Achievable Potential (aMW)

Bundle	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
0-10th Percentile	1	3	4	6	7	9	11	13	15	17
10-20th Percentile	3	3	5	6	8	10	11	13	15	17
20-30th Percentile	3	5	7	9	12	14	16	18	20	22
30-40th Percentile	1	3	5	6	8	10	12	14	16	18
40-50th Percentile	2	3	5	6	8	10	11	13	14	16
50-60th Percentile	1	3	4	6	7	8	10	11	13	14
60-70th Percentile	2	4	6	9	11	13	15	17	19	21
70-80th Percentile	3	6	10	13	16	19	21	23	25	27
80-90th Percentile	2	5	7	10	13	16	19	21	24	26
90-100th Percentile	2	4	6	8	11	14	16	19	22	24
High Cost	2	5	8	11	14	17	20	23	25	27
Total	**24**	**44**	**67**	**90**	**115**	**140**	**163**	**186**	**208**	**228**

Bundle	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
0-10th Percentile	19	21	23	25	27	29	30	31	32	33
10-20th Percentile	19	20	22	25	27	28	30	31	32	33
20-30th Percentile	23	25	26	28	29	31	32	32	33	34
30-40th Percentile	20	22	24	25	27	28	30	31	32	33
40-50th Percentile	17	19	21	23	25	27	28	30	32	34
50-60th Percentile	15	17	19	20	22	24	26	29	31	33
60-70th Percentile	22	24	25	26	28	29	30	31	32	33
70-80th Percentile	28	29	30	31	32	32	33	33	33	34
80-90th Percentile	28	29	30	31	31	32	32	33	33	34
90-100th Percentile	26	28	29	30	30	31	32	32	33	33
High Cost	29	31	33	34	35	37	38	39	40	41
Total	**247**	**265**	**282**	**298**	**314**	**327**	**340**	**352**	**364**	**375**

Bundle Costs

Savings-Weighted Levelized Cost of Energy ($/MWh) Real Dollars

Bundle	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
0-10th Percentile	-$115	-$111	-$106	-$102	-$99	-$97	-$108	-$108	-$105	-$104
10-20th Percentile	-$5	-$8	-$7	-$5	-$5	-$5	-$15	-$15	-$15	-$15
20-30th Percentile	$14	$14	$14	$14	$14	$15	$14	$14	$15	$15
30-40th Percentile	$38	$38	$38	$38	$38	$38	$32	$32	$32	$32
40-50th Percentile	$42	$42	$42	$42	$41	$42	$40	$40	$39	$39
50-60th Percentile	$56	$56	$55	$55	$55	$55	$56	$55	$55	$54
60-70th Percentile	$68	$69	$69	$69	$69	$69	$69	$69	$69	$69
70-80th Percentile	$138	$138	$139	$139	$139	$139	$136	$133	$130	$127
80-90th Percentile	$133	$135	$136	$137	$138	$137	$135	$134	$133	$132
90-100th Percentile	$192	$190	$189	$188	$188	$188	$187	$187	$187	$188
High Cost	$2,145	$2,144	$2,121	$2,094	$2,063	$2,001	$1,936	$1,876	$1,866	$1,906
Total	**$277**	**$312**	**$322**	**$330**	**$331**	**$325**	**$299**	**$285**	**$278**	**$271**

Bundle	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	20-Year Average
0-10th Percentile	-$103	-$105	-$104	-$103	-$103	-$91	-$92	-$89	-$83	-$90	-$102
10-20th Percentile	-$15	-$27	-$27	-$27	-$27	-$28	-$29	-$29	-$30	-$30	-$18
20-30th Percentile	$15	$15	$15	$15	$15	$15	$15	$13	$13	$12	$14
30-40th Percentile	$32	$27	$27	$27	$26	$26	$26	$27	$27	$27	$32
40-50th Percentile	$38	$35	$35	$34	$34	$34	$34	$34	$34	$34	$38
50-60th Percentile	$52	$45	$44	$43	$42	$42	$42	$40	$40	$40	$48
60-70th Percentile	$70	$69	$69	$69	$69	$69	$69	$69	$69	$69	$69
70-80th Percentile	$123	$120	$116	$112	$109	$107	$76	$73	$71	$69	$131
80-90th Percentile	$131	$130	$128	$126	$124	$121	$110	$111	$111	$112	$133
90-100th Percentile	$189	$190	$192	$194	$195	$196	$195	$195	$195	$195	$189
High Cost	$2,025	$2,204	$2,424	$2,653	$2,858	$3,049	$3,260	$3,261	$3,366	$3,463	$2,235
Total	**$267**	**$257**	**$257**	**$257**	**$259**	**$292**	**$296**	**$329**	**$359**	**$384**	$290

SUPPLY-SIDE RESOURCE DATA

Key Financial and Forecast Assumptions

Financing Cap Structure and Cost	
Composition	
Debt	50.10%
Preferred	0.00%
Common	49.90%
Total	**100.00%**
Cost	
Debt	5.73%
Preferred	0.00%
Common	10.00%
Average Weighted Cost	7.86%

Financial Assumptions and Factors	
Plant operating (book) life	Expected Life of the Asset
Discount rate (weighted average cost of capital)	9.59%
After-tax discount rate	7.12%
Composite tax rate	25.74%
Deferred rate	21.30%
General O&M escalation rate	2.20%
Annual property tax rate (% of investment)	0.29%
Property tax escalation rate	3.00%
Annual insurance premiums (% of investment)	0.31%
Insurance escalation rate	2.00%
AFUDC rate (annual)	7.65%

Discount Rate

Idaho Power used a consistent discount rate of 9.59 percent for all present value and levelization calculations in the 2019 IRP. This discount rate reflects IPC's weighted average cost of capital (WACC) of 7.12 percent, plus a grossed-up amount for tax for the portion of costs financed by equity. This is a shift in philosophy from prior IRPs when the traditional WACC was used for all discounting calculations. Portfolio cost streams, resource cost streams, etc. in the IRP reflect Idaho Power's estimated revenue requirements over the planning periods. Revenue requirement ultimately reflects amounts charged to customers that allow a utility to recoup its costs and achieve an allowed rate of return. Income tax expense on earnings derived from equity financing is one of the expenses that is charged to customers in rates. It is this perspective that primarily drove the discount rate shift in the 2019 IRP to the higher "grossed-up" equity discount rate. Although different, the continued application of a consistent discount rate across the various financial calculations in the IRP allows for reasonable comparability of resource and portfolio costs. Idaho Power is committed to further discussion and technical alignment with stakeholders around the discount rate that will be used in the 2021 IRP.

Fuel Forecast Base Case (Nominal, $ per MMBTU)

Year	Generic Coal	Nuclear
2019	$2.40	
2020	$2.49	
2021	$2.55	
2022	$2.62	
2023	$2.68	$0.62
2024	$2.74	$0.63
2025	$2.80	$0.65
2026	$2.86	$0.66
2027	$2.91	$0.68
2028	$2.96	$0.69
2029	$3.01	$0.71
2030	$3.08	$0.72
2031	$3.15	$0.74
2032	$3.21	$0.75
2033	$3.30	$0.77
2034	$3.39	$0.79
2035	$3.46	$0.81
2036	$3.57	$0.82
2037	$3.65	$0.84
2038	$3.75	$0.86

Cost Inputs and Operating Assumptions (Costs in 2019$)

Supply-Side Resources	Plant Capacity (MW)	Plant Capital ($/kW)[1,3]	Transmission Capital ($/kW)	Total Capital ($/kW)	Total Investment ($/kW)[2]	Fixed O&M ($/kW-mth)[3]	Variable O&M ($/MWh)	Integration ($/MWh)	Heat Rate (Btu/kWh)	Economic Life (years)
Biomass (35 MW)	35	$3,577	$133	$3,710	$4,614	$3.13	$16.68	$0.00	0	30
Boardman to Hemingway (350 MW)	350	$0	$894	$894	$894	$0.42	$0.00	$0.00	0	55
CCCT (1x1) F Class (300 MW)	300	$1,096	$102	$1,198	$1,401	$0.92	$2.90	$0.00	6,420	30
Geothermal (30 MW)	30	$6,014	$150	$6,164	$7,904	$15.05	$0.00	$0.00	0	25
Reciprocating Gas Engine (111.1 MW)	111	$885	$117	$1,002	$1,067	$1.00	$5.42	$0.00	8,300	40
Reciprocating Gas Engine (55.5 MW)	56	$994	$117	$1,111	$1,183	$1.00	$5.42	$0.00	8,300	40
SCCT—Frame F Class (170 MW)	170	$932	$122	$1,054	$1,122	$1.07	$7.48	$0.00	9,720	35
Small Modular Nuclear (60 MW)	60	$4,292	$165	$4,457	$6,722	$0.70	$2.09	$0.00	11,493	40
Solar PV—Residential Rooftop (.005 MW)	0.005	$3,590	$0	$3,590	$3,730	$1.79	$0.00	$0.00	0	25
Solar PV—Utility Scale 1-Axis Tracking (40 MW)	40	$1,402	$150	$1,552	$1,613	$1.02	$0.00	$0.63	0	30
Solar PV—Utility Scale 1-Axis Tracking (40 MW) w/ 4-hr Battery (10 MW)	50	$1,658	$150	$1,808	$1,879	$0.97	$0.49	$0.63	0	30
Solar PV—Utility Scale 1-Axis Tracking (40 MW) w/ 4-hr Battery (20 MW)	60	$1,829	$150	$1,979	$2,056	$0.94	$0.81	$0.63	0	30
Solar PV—Utility Scale 1-Axis Tracking (40 MW) w/ 4-hr Battery (30 MW)	70	$1,950	$150	$2,100	$2,183	$0.92	$1.03	$0.63	0	30
Solar PV—Targeted Siting for Grid Benefit (0.5 MW)	0.5	$1,823	-$62	$1,761	$1,830	$0.93	$0.00	$0.00	0	25
Storage—Li Battery 4 hour (5 MW)	5	$1,973	$52	$2,025	$2,064	$0.78	$2.47	$0.00	0	20
Storage—Li Battery 8 hour (5 MW)	5	$3,277	$52	$3,329	$3,393	$0.78	$2.47	$0.00	0	10
Storage—Pumped-Hydro (500 MW)	500	$1,800	$191	$1,991	$2,315	$0.33	$0.00	$0.00	0	75
Wind ID (100 MW)	100	$1,623	$122	$1,745	$1,863	$4.47	$0.00	$20.29	0	25
Wind WY (100 MW)	100	$1,623	$122	$1,745	$1,863	$4.47	$0.00	$20.29	0	25

[1] Plant costs include engineering development costs, generating and ancillary equipment purchase, and installation costs, as well as balance of plant construction.
[2] Total Investment includes capital costs and AFUDC.
[3] Fixed O&M excludes property taxes and insurance (separately calculated within the levelized resource cost analysis)

Levelized Cost of Energy (Costs in 2023$, $/MWh)[1]

At stated capacity factors

Supply-Side Resources	Cost of Capital	Non-Fuel O&M[2]	Fuel	Wholesale Energy	Net of Tax Credit/ Integration	Total Cost per MWh	Capacity Factor
Biomass (35 MW)[3]	$69	$36	$0	$0	$0	$104	85%
Boardman to Hemingway (350 MW)	$26	$3	$0	$40	$0	$69	33%
CCCT (1x1) F Class (300 MW)	$29	$9	$33	$0	$0	$72	60%
Geothermal (30 MW)	$107	$40	$0	$0	$0	$148	88%
Reciprocating Gas Engine (111.1 MW)	$84	$28	$45	$0	$0	$157	15%
Reciprocating Gas Engine (55.5 MW)	$94	$29	$45	$0	$0	$167	15%
SCCT—Frame F Class (170 MW)	$273	$74	$52	$0	$0	$398	5%
Small Modular Nuclear (60 MW)	$89	$27	$9	$0	$0	$125	90%
Solar PV—Residential Rooftop (.005 MW)	$161	$25	$0	$0	$0	$186	21%
Solar PV—Utility Scale 1-Axis Tracking (40 MW)	$63	$12	$0	$0	-$6	$68	26%
Solar PV—Utility Scale 1-Axis Tracking (40 MW) w/ 4-Hr Battery (10 MW)	$86	$15	$0	$0	-$9	$92	22%
Solar PV—Utility Scale 1-Axis Tracking (40 MW) w/ 4-Hr Battery (20 MW)	$115	$20	$0	$0	-$12	$122	18%
Solar PV—Utility Scale 1-Axis Tracking (40 MW) w/ 4-Hr Battery (30 MW)	$146	$25	$0	$0	-$16	$155	15%
Solar PV—Targeted Siting for Grid Benefit (0.5 MW)	$74	$12	$0	$0	-$8	$78	26%
Storage—Li Battery 4 hour (5 MW)[3]	$209	$30	$0	$0	$0	$239	11%
Storage—Li Battery 8 hour (5 MW)[3]	$236	$19	$0	$0	$0	$255	23%
Storage—Pumped-Hydro (500 MW)[3]	$164	$19	$0	$0	$0	$183	16%
Wind ID (100 MW)	$63	$28	$0	$0	$25	$116	35%
Wind WY (100 MW)	$49	$22	$0	$0	$25	$96	45%

[1] Levelized costing in 2023$ assuming 2023 online date. Common online date five years into IRP planning window allows levelized costing to capture projected trends in resource costs.
[2] Non-Fuel O&M includes fixed and variable costs, property taxes.
[3] Fuel costs not included for biomass resource. Storage resources do not include costs of recharge energy. As noted in IRP, levelized costing for storage resources driven overwhelmingly by fixed costs.

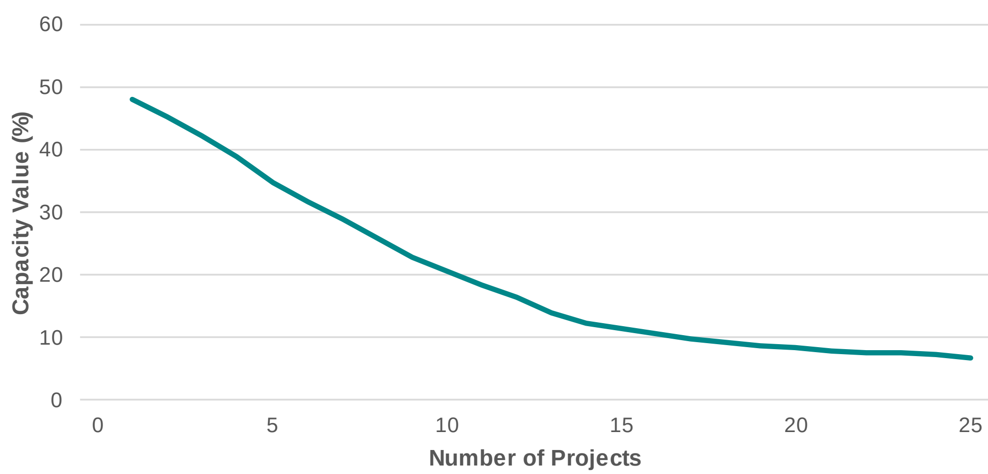
Levelized Capacity (fixed) Cost per kW/Month (Costs in 2019$)

Supply-Side Resources	Cost of Capital	Non-Fuel O&M	Tax Credit	Total Cost per kW
Biomass (35 MW)	$39	$7		$46
Boardman to Hemingway (350 MW)	$6	$1		$7
CCCT (1x1) F Class (300 MW)	$12	$2		$14
Geothermal (30 MW)	$64	$24		$88
Reciprocating Gas Engine (111.1 MW)	$9	$2		$11
Reciprocating Gas Engine (55.5 MW)	$9	$2		$12
SCCT—Frame F Class (170 MW)	$9	$2		$11
Small Modular Nuclear (60 MW)	$54	$5		$59
Solar PV—Residential Rooftop (.005 MW)	$30	$2		$33
Solar PV—Utility Scale 1-Axis Tracking (40 MW)	$12	$2	-$1	$13
Solar PV—Utility Scale 1-Axis Tracking (40 MW) w/ 4-Hr Battery (10 MW)	$14	$2	-$2	$15
Solar PV—Utility Scale 1-Axis Tracking (40 MW) w/ 4-Hr Battery (20 MW)	$16	$3	-$2	$17
Solar PV—Utility Scale 1-Axis Tracking (40 MW) w/ 4-Hr Battery (30 MW)	$17	$3	-$2	$18
Solar PV—Targeted Siting for Grid Benefit (0.5 MW)	$15	$2	-$2	$16
Storage—Li Battery 4 hour (5 MW)	$18	$2		$20
Storage—Li Battery 8 hour (5 MW)	$44	$3		$47
Storage—Pumped-Hydro (500 MW)	$18	$2		$20
Wind ID (100 MW)	$15	$7		$22
Wind WY (100 MW)	$15	$7		$22

Solar Peak-Hour Capacity Credit (contribution to peak)

	Project MWAC	Total Installed MWAC ABV Current	Project Capacity Value (% Proj MWAC)	Project Capacity Value (MWAC)
Project 1	40	40	45.4%	18.1
Project 2	40	80	42.1%	16.9
Project 3	40	120	38.8%	15.5
Project 4	40	160	34.7%	13.9
Project 5	40	200	31.6%	12.7
Project 6	40	240	28.8%	11.5
Project 7	40	280	25.9%	10.4
Project 8	40	320	22.8%	9.1
Project 9	40	360	20.5%	8.2
Project 10	40	400	18.3%	7.3
Project 11	40	440	16.4%	6.5
Project 12	40	480	14.0%	5.6
Project 13	40	520	12.4%	5.0
Project 14	40	560	11.6%	4.6
Project 15	40	600	10.6%	4.2
Project 16	40	640	9.9%	4.0
Project 17	40	680	9.4%	3.7
Project 18	40	720	8.7%	3.5
Project 19	40	760	8.5%	3.4
Project 20	40	800	8.0%	3.2
Project 21	40	840	7.7%	3.1
Project 22	40	880	7.7%	3.1
Project 23	40	920	7.2%	2.9
Project 24	40	960	6.9%	2.8

Capacity value of incremental solar PV projects (40 MW each)



PURPA Reference Data

The following information is provided for PURPA reference purposes.

1. Preferred portfolio: Portfolio P14

Resource Portfolio P14

Date	Resource	Installed Capacity (MW)	Peak-Hour Capacity (MW)
2019	North Valmy Unit 1	(127)	(127)[1]
2020	Boardman	(58)	(58)[2]
2022	Solar	120	51
2022	Jim Bridger Unit	(177)	(177)
2023	Solar	100	32
2025	North Valmy Unit 2	(133)	(133)[1]
2026	B2H	500 (Apr–Sep)/ 200 (Oct–Mar)	500
2026	Demand Response	5	5
2026	Jim Bridger Unit	(174)	(174)
2028	Reciprocating engines	111	111
2029	Demand Response	5	5
2030	Reciprocating engines	111	111
2030	Demand Response	5	5
2031	Demand Response	5	5
2032	Demand Response	5	5
2033	Demand Response	5	5
2034	Solar	45	12
2034	Battery Storage	30	30
2034	Demand Response	5	5
2034	Jim Bridger Units	(357)	(357)
2035	CCCT	300	300
2035	Solar	40	18
2035	Battery Storage	20	10
2035	Demand Response	5	5
2036	Demand Response	5	5
2037	Solar	40	9
2037	Battery Storage	10	10
2038	CCCT	300	300
2038	Demand Response	5	5

1. Exit from North Valmy units not considered to affect capacity deficiency period because of IRP’s assumed peak-hour wholesale electric market imports across existing North Valmy transmission line
2. Ceased coal-fired operations at Boardman in 2020 considered committed resource action.

2. Deficiency period start

   First capacity deficit = (42) MW July 2029

3. Intermittent generation integration costs

   Idaho—Schedule 87[2]

   Oregon—Schedule 85[3]

Renewable Energy Certificate Forecast

Year	Nominal ($/MWh)
2019	4.84
2020	5.04
2021	5.31
2022	5.33
2023	5.44
2024	5.73
2025	5.75
2026	5.85
2027	5.89
2028	6.16
2029	6.21
2030	6.48
2031	6.53
2032	6.94
2033	7.07
2034	7.17
2035	7.55
2036	7.66
2037	8.04
2038	8.04

[2] idahopower.com/about-us/company-information/rates-and-regulatory/retail-tariffs-idaho/

[3] idahopower.com/about-us/company-information/rates-and-regulatory/oregon-special-agreements/

Existing Resource Data

Qualifying Facility Data (PURPA)

Cogeneration and Small Power Production Projects Status as of April 1, 2019.

		Contract				Contract	
Project	**MW**	**On-line Date**	**End Date**	**Project**	**MW**	**On-line Date**	**End Date**
Hydro Projects							
Arena Drop	0.45	Sep-2010	Sep-2030	Littlewood/Arkoosh	0.87	Aug-1986	Aug-2021
Baker City Hydro	0.24	Sep-2015	Sep-2030	Low Line Canal	7.97	May-1985	May-2020
Barber Dam	3.70	Apr-1989	Apr-2024	Low Line Midway Hydro	2.50	Aug-2007	Aug-2027
Birch Creek	0.05	Nov-1984	Nov-2019	Lowline #2	2.79	Apr-1988	Apr-2023
Black Canyon #3	0.13	Apr-2019	Apr-2039	Magic Reservoir	9.07	Jun-1989	Jun-2024
Black Canyon Bliss Hydro	0.03	Nov-2014	Oct-2035	Malad River	1.17	May-2019	May-2039
Blind Canyon	1.63	Dec-2014	Dec-2034	Marco Ranches	1.20	Aug-1985	Aug-2020
Box Canyon	0.30	Feb-2019	Feb-2039	MC6 Hydro	2.10	Jul-2019	Jul-2039
Briggs Creek	0.60	Oct-1985	Oct-2020	Mile 28	1.50	Jun-1994	Jun-2029
Bypass	9.96	Jun-1988	Jun-2023	Mitchell Butte	2.09	May-1989	Dec-2033
Canyon Springs	0.11	Jan-2019	Jan-2039	Mora Drop Small Hydro	1.85	Sep-2006	Sep-2026
Cedar Draw	1.55	Jun-1984	Jun-2019	Mud Creek/S&S	0.52	Feb-2017	Feb-2037
Clear Springs Trout	0.56	Nov-2018	Nov-2038	Mud Creek/White	0.21	Jan-1986	Jan-2021
Crystal Springs	2.44	Apr-1986	Apr-2021	North Gooding Main	1.30	Oct-2016	Oct-2036
Curry Cattle Company	0.25	Jun-2018	Jun-2033	Owyhee Dam CSPP	5.00	Aug-1985	May-2033
Dietrich Drop	4.50	Aug-1988	Aug-2023	Pigeon Cove	1.89	Oct-1984	Oct-2019
Eightmile Hydro Project	0.36	Oct-2014	Oct-2034	Pristine Springs #1	0.10	May-2015	May-2020
Elk Creek	2.00	May-1986	May-2021	Pristine Springs #3	0.20	May-2015	May-2020
Fall River	9.10	Aug-1993	Aug-2028	Reynolds Irrigation	0.26	May-1986	May-2021
Fargo Drop Hydroelectric	1.27	Apr-2013	Apr-2033	Rock Creek #1	2.17	Jan-2018	Jan-2038
Faulkner Ranch	0.87	Aug-1987	Aug-2022	Rock Creek #2	1.90	Apr-1989	Apr-2024
Fisheries Dev.	0.26	Jul-1990	As Delivered	Sagebrush	0.43	Sep-1985	Sep-2020
Geo-Bon #2	0.93	Nov-1986	Nov-2021	Sahko Hydro	0.50	Feb-2011	Feb-2021
Hailey CSPP	0.06	Jun-1985	Jun-2020	Schaffner	0.53	Aug-1986	Aug-2021
Hazelton A	8.10	Mar-2011	Mar-2026	Shingle Creek	0.22	Aug-2017	Aug-2022
Hazelton B	7.60	May-1993	May-2028	Shoshone #2	0.58	May-1996	May-2031
Head of U Canal Project	1.28	May-2015	Jun-2035	Shoshone CSPP	0.36	Feb-2017	Feb-2037
Horseshoe Bend Hydro	9.50	Sep-1995	Sep-2030	Snake River Pottery	0.07	Nov-1984	Nov-2019
Jim Knight	0.34	Jun-1985	Jun-2020	Snedigar	0.54	Jan-1985	Jan-2020
Koyle Small Hydro	1.25	Apr-2019	Apr-2039	Tiber Dam	7.50	Jun-2004	Jun-2024
Lateral # 10	2.06	May-1985	May-2020	Trout-Co	0.24	Dec-1986	Dec-2021
Lemoyne	0.08	Jun-1985	Jun-2020	Tunnel #1	7.00	Jun-1993	Feb-2035
Little Wood River Ranch II	1.25	Jun-2015	Oct-2035	White Water Ranch	0.16	Aug-1985	Aug-2020
Little Wood River Res	2.85	Feb-1985	Feb-2020	Wilson Lake Hydro	8.40	May-1993	May-2028

Total Hydro Nameplate Rating 148.85 MW

Thermal Projects			
Simplot Pocatello Cogen	15.90	Mar-2019	Mar-2022
TASCO—Nampa Natural Gas	2	Sep-2003	As Delivered
TASCO—Twin Falls Natural Gas	3	Aug-2001	As Delivered
Total Thermal Nameplate Rating 20.90 MW			

Project	MW	Contract On-line Date	End Date	Project	MW	Contract On-line Date	End Date
Biomass Projects							
B6 Anaerobic Digester	2.28	Aug-2010	Aug-2020	Hidden Hollow Landfill Gas	3.20	Jan-2007	Jan-2027
Bannock County Landfill	3.20	May-2014	May-2034	Pocatello Waste	0.46	Dec-1985	Dec-2020
Bettencourt Dry Creek	2.25	May-2010	May-2020	Rock Creek Dairy	4.00	Aug-2012	Aug-2027
Big Sky West Dairy Digester	1.50	Jan-2009	Jan-2029	SISW LFGE	5.00	Oct-2018	Estimated
Double A Digester Project	4.50	Jan-2012	Jan-2032	Tamarack CSPP	6.25	Jun-2018	Jun-2038
Fighting Creek Landfill	3.06	Apr-2014	Apr-2029				
Total Biomass Nameplate Rating 35.70 MW							

Solar Projects							
American Falls Solar II, LLC	20.00	Mar-2017	Mar-2037	Murphy Flat Power, LLC	20.00	Mar-2017	Mar-2037
American Falls Solar, LLC	20.00	Mar-2017	Mar-2037	Ontario Solar Center	3.00	Dec-2019	Estimated
Baker Solar Center	15.00	Dec-2019	Estimated	Open Range Solar Center, LLC	10.00	Mar-2017	Mar-2037
Brush Solar	2.75	Oct-2019	Estimated	Orchard Ranch Solar, LLC	20.00	Oct-2016	Oct-2036
Grand View PV Solar Two	80.00	Dec-2016	Dec-2036	Railroad Solar Center, LLC	4.50	Dec-2016	Dec-2036
Grove Solar Center, LLC	6.00	Oct-2016	Oct-2036	Simcoe Solar, LLC	20.00	Mar-2017	Mar-2037
Hyline Solar Center, LLC	9.00	Nov-2016	Nov-2036	Thunderegg Solar Center, LLC	10.00	Nov-2016	Nov-2036
ID Solar 1	40.00	Aug-2016	Jan-2036	Vale Air Solar Center, LLC	10.00	Nov-2016	Nov-2036
Morgan Solar	3.00	Oct-2019	Estimated	Vale 1 Solar	3.00	Oct-2019	Estimated
Mt. Home Solar 1, LLC	20.00	Mar-2017	Mar-2037				
Total Solar Nameplate Rating 316.25 MW							

Wind Projects							
Bennett Creek Wind Farm	21.00	Dec-2008	Dec-2028	Mainline Windfarm	23.00	Dec-2012	Dec-2032
Benson Creek Windfarm	10.00	Mar-2017	Mar-2037	Milner Dam Wind	19.92	Feb-2011	Feb-2031
Burley Butte Wind Park	21.30	Feb-2011	Feb-2031	Oregon Trail Wind Park	13.50	Jan-2011	Jan-2031
Camp Reed Wind Park	22.50	Dec-2010	Dec-2030	Payne's Ferry Wind Park	21.00	Dec-2010	Dec-2030
Cassia Wind Farm LLC	10.50	Mar-2009	Mar-2029	Pilgrim Stage Station Wind Park	10.50	Jan-2011	Jan-2031
Cold Springs Windfarm	23.00	Dec-2012	Dec-2032	Prospector Windfarm	10.00	Mar-2017	Mar-2037
Desert Meadow Windfarm	23.00	Dec-2012	Dec-2032	Rockland Wind Farm	80.00	Dec-2011	Dec-2036
Durbin Creek Windfarm	10.00	Mar-2017	Mar-2037	Ryegrass Windfarm	23.00	Dec-2012	Dec-2032
Fossil Gulch Wind	10.50	Sep-2005	Sep-2025	Salmon Falls Wind	22.00	Apr-2011	Apr-2031
Golden Valley Wind Park	12.00	Feb-2011	Feb-2031	Sawtooth Wind Project	22.00	Nov-2011	Nov-2031
Hammett Hill Windfarm	23.00	Dec-2012	Dec-2032	Thousand Springs Wind Park	12.00	Jan-2011	Jan-2031
High Mesa Wind Project	40.00	Dec-2012	Dec-2032	Tuana Gulch Wind Park	10.50	Jan-2011	Jan-2031
Horseshoe Bend Wind	9.00	Feb-2006	Feb-2026	Tuana Springs Expansion	35.70	May-2010	May-2030
Hot Springs Wind Farm	21.00	Dec-2008	Dec-2028	Two Ponds Windfarm	23.00	Dec-2012	Dec-2032
Jett Creek Windfarm	10.00	Mar-2017	Mar-2037	Willow Spring Windfarm	10.00	Mar-2017	Mar-2037
Lime Wind Energy	3.00	Dec-2011	Dec-2031	Yahoo Creek Wind Park	21.00	Dec-2010	Dec-2030
Total Wind Nameplate Rating 626.92 MW							
Total Nameplate Rating 1,148.62 MW							

The above is a summary of the Nameplate rating for the CSPP projects under contract with Idaho Power as of April 1, 2019. In the case of CSPP projects, Nameplate rating of the actual generation units is not an accurate or reasonable estimate of the actual energy these projects will deliver to Idaho Power. Historical generation information, resource specific industry standard capacity factors, and other known and measurable operating characteristics are accounted for in determining a reasonable estimate of the energy these projects will produce.

Power Purchase Agreement Data

Idaho Power Company Power Purchase Agreements Status as of April 1, 2019

Project	MW	Contract On-Line Date	End Date
Wind projects			
Elkhorn Wind Project	101	December 2007	December 2027
Total Wind Nameplate Rating	**101**		
Geothermal Projects			
Raft River Unit 1	13	April 2008	April 2033
Neal Hot Springs	22	November 2012	November 2037
Total Geothermal Nameplate Rating	**35**		
Solar projects			
Jackpot Solar Facility	120	December 2022	Estimated
Total Solar Nameplate Rating	**120**		
Total Nameplate Rating	**256**		

The above is a summary of the Nameplate rating for the CSPP projects under contract with Idaho Power as of April 1, 2019. In the case of CSPP projects, Nameplate rating of the actual generation units is not an accurate or reasonable estimate of the actual energy these projects will deliver to Idaho Power. Historical generation information, resource specific industry standard capacity factors, and other known and measurable operating characteristics are accounted for in determining a reasonable estimate of the energy these projects will produce.

Flow Modeling

Models

Idaho Power uses two primary models to develop future flow scenarios for the IRP. The Snake River Planning Model (SRPM) is used to model surface water flows and the Enhanced Snake Plain Aquifer Model (ESPAM) is used to model aquifer management practices implemented on the Eastern Snake Plain Aquifer (ESPA). The SRPM was updated in late 2012 to include hydrologic conditions for years 1928 through 2009. ESPAM was also updated with the release of ESPAM 2.1 in late 2012. Beginning with the 2009 IRP, Idaho Power began running the SRPM and ESPAM as a combined modeling system. The combined model seeks to maximize diversions for aquifer recharge and system conversions without creating additional model irrigation shortages over a modeled reference condition.

Model Inputs

The inputs for the 2019 IRP were derived, in part, from management practices outlined in an agreement between the Surface Water Coalition (SWC) and Idaho Groundwater Appropriators (IGWA). The agreement set out specific targets for several management practices that include aquifer recharge, system conversions, and a total reduction in ground water diversions of 240,000 acre-feet. Model inputs also included a long-term analysis of trends in reach gains to the Snake River from Palisades Dam to King Hill. Weather modification activities conducted by Idaho Power and other participating entities were included in the modeling effort.

Recharge capacity modeled for the 2019 IRP included diversions with the capability of diverting all available water at the Snake River below Milner Dam during the winter months under typical release conditions. These diversions can have a significant impact to flows downstream of Milner Dam. Modeled recharge diversions peak at approximately 339,000 acre-ft in IRP year 2025. In IRP year 2025, approximately 145,000 acre-ft of recharge diversions occur above American Falls Reservoir and 195,000 acre-ft is diverted at Milner Dam. Modeled recharge diversions decline only slightly from the peak in 2025 through the end of the modeling period in 2038. The 2019 IRP included approximately 85,000 acre-ft of additional annual recharge not included in the 2017 IRP. This increase in projected recharge activity is based upon recharge activity observed from spring 2016 through spring 2018. The additional annual recharge volume can be attributed to the development of private aquifer recharge and state sponsored recharge demonstrating a higher level of recharge capacity than anticipated in the 2017 IRP.

System conversion projects involve the conversion of ground water supplied irrigated land to surface water-supplied irrigated land. The number of acres modeled and potential water savings was based on data provided by the Idaho Department of Water Resources and local ground water districts. The current model assumes a total of 48,000 acres of converted land on the ESPA. This is an increase of approximately 30,000 acres over the 2017 IRP and is based on data collected from a local groundwater district. Water savings for conversion projects are calculated at a rate of 2.0 acre-ft per converted acre. Diversions for conversion projects peak at approximately 95,000 acre-ft in model year 2024 and are held essentially constant through the end of the modeling period in year 2038.

The model accounted for a 190,000 acre-ft decrease in ground water pumping from the ESPA. The decrease was spread evenly over ground water irrigated lands that are subject to the agreement between the SWC and the IGWA. The SWC agreement requires a total reduction of 240,000 acre-ft per year but the agreement allows for a portion of that to be offset by aquifer recharge activities. Based on recent management activity, approximately 50,000 acre-ft per year reduction is accomplished through other forms of mitigation such as private aquifer recharge.

The 2019 IRP modeling also recognized ongoing declines in specific reaches. Future reach declines were determined using a variety of statistical analyses. Trend data indicate reach gains into American Falls Reservoir and from Lower Salmon Falls Dam to Bliss demonstrated a statistically significant decline for the period of 1988 to 2017. The long-term declines are still present, but they have improved since the 2017 IRP. Reach gains to the Snake River increased in 2016 and 2017. The increases in reach gains may be due to a combination of factors including recent high runoff events, good supply of irrigation water, and aquifer recharge activities. The declines calculated for the 2019 IRP are approximately 25 to 30 percent less than those used in the 2017 IRP. This results in additional water in the Snake River throughout the planning period.

Weather modification was added to the model at various levels of development. For IRP years 2019 through 2024, weather modification was increased to reflect projected levels of program development in Eastern Idaho, the Wood River and Boise basins. Beyond IRP year 2024, weather-modification levels in these three basins were held constant through the remainder of the IRP planning period. The level of weather modification was held constant at the current level in the Payette River Basin throughout the IRP planning period.

The modeling also accounts for changes in reach gains from observed water management activities on the ESPA since 2014. Reach gain calculations include management activities that have occurred since 2014. Data from IDWR and other sources were used to determine the magnitude of the management activities and the ESPAM was used to model the projected reach gains. The impact of those management activities can have impacts on reach gains for up to 30 years.

Model Results

The combined model allows for the inclusion of all future management activities, and the resulting reach gains from those management activities into Idaho Power's 2019 IRP. Management activities, such as recharge and system conversions, do not significantly change the total annual volume of water expected to flow through the Hells Canyon Complex (HCC), but instead change the timing and location of reach gains within the system. Other future management activities, such as weather modification and a decrease in ground water pumping, directly impact the annual volume of water expected through the HCC as well as the timing and location of gains within the system.

Overall inflow to Brownlee Reservoir increases from IRP modeled year 2019 through 2024. Flows peak in 2025 with the 50 percent exceedance annual inflow to Brownlee Reservoir at just over 12.33 million acre-ft/year. In 2038, those flows declined to approximately 12.03 million acre-ft per year. For the April through July volume the peak occurs in modeled year 2024 with a volume of 5.58 million acre-ft. In the final modeled year of 2038, the April through July inflow to Brownlee decreases to 5.47 million acre-ft.

The Brownlee inflow volumes for the 2019 IRP are higher than those reported in the 2017 IRP. There are several factors leading to the increase in modeled flows. The change in reach declines had a significant impact on inflows to Brownlee Reservoir. For example, in model year 2036, the increase in Brownlee inflow volume attributable to changes in reach declines between the 2019 and 2017 IRPs is approximately 337,000 acre-feet, Weather modification volume increased by approximately 200,000 acre-ft per year in the 2019 IRP as compared to the 2017 IRP. The other notable change is the observed recharge conducted in 2016 and 2017 exceeded recharge volume assumptions made during the 2017 IRP.

Over 1,000,000 acre-ft water were recharged to the ESPA during 2016 and 2017. While outside the modeling period of 2019 to 2038, the reach gains resulting from this recharge are modeled and significantly increase reach gains for the modeling period. The modeled reach gains from this recharge increased reach gains in the Snake River and inflows to Brownlee Reservoir particularly during the first five years of the modeling period.

2019 Model Parameters (acre foot/year)

	Managed Recharge						Reach Declines	
Year	Above American Falls	Below American Falls	Total	Weather Modification	System Conversions	Ground Water Pumping Declines	American Falls Inflows	Below Milner Inflows
2019	145,210	192,991	338,201	978,140	96,138	190,053	167,239	135,702
2020	144,682	193,002	337,685	1,164,927	95,105	190,053	182,442	148,039
2021	144,559	193,002	337,562	1,232,907	95,105	190,053	197,646	160,375
2022	144,436	193,052	337,489	1,241,693	96,140	190,053	212,849	172,712
2023	144,680	193,298	337,978	1,252,091	95,105	190,053	228,053	185,049
2024	144,381	193,187	337,568	1,268,605	95,537	190,053	243,256	197,385
2025	144,319	194,802	339,121	1,268,605	94,928	190,053	258,460	209,722
2026	144,319	193,195	337,514	1,268,605	94,928	190,053	273,663	222,058
2027	144,319	193,139	337,459	1,268,605	94,928	190,053	288,867	234,395
2028	144,319	193,024	337,344	1,268,605	94,928	190,053	304,071	246,732
2029	144,319	192,913	337,233	1,268,605	94,928	190,053	319,274	259,068
2030	144,490	192,669	337,159	1,268,605	95,414	190,053	334,478	271,405
2031	143,631	192,550	336,181	1,268,605	95,351	190,053	349,681	283,741
2032	143,508	192,429	335,937	1,268,605	95,351	190,053	364,885	296,078
2033	143,693	192,364	336,056	1,268,605	95,412	190,053	380,088	308,414
2034	143,262	192,001	335,263	1,268,605	95,535	190,053	395,292	320,751
2035	143,865	192,058	335,924	1,268,605	95,535	190,053	410,495	333,088
2036	143,324	191,878	335,202	1,268,605	95,535	190,053	425,699	345,424
2037	143,139	191,691	334,831	1,268,605	95,291	190,053	440,902	357,761
2038	142,467	191,634	334,101	1,268,605	95,172	190,053	456,106	370,097

Hydro Modeling Results (aMW)

		50th Percentile			70th Percentile			90th Percentile		
Year	**Month**	**HCC***	**ROR****	**Total**	**HCC**	**ROR**	**Total**	**HCC**	**ROR**	**Total**
2019	Jan	750	350	1,100	596	204	800	434	177	612
	Feb	787	355	1,141	682	310	993	682	310	993
	Mar	815	276	1,092	588	225	813	588	225	813
	Apr	1,058	406	1,465	750	274	1,024	750	274	1,024
	May	913	432	1,344	875	320	1,195	875	320	1,195
	June	992	385	1,377	678	333	1,011	678	333	1,011
	July	551	292	842	520	282	802	520	282	802
	Aug	466	251	716	437	242	679	437	242	679
	Sept	568	241	809	464	231	696	464	231	696
	Oct	417	215	632	395	206	601	395	206	601
	Nov	343	195	538	347	180	527	347	180	527
	Dec	579	362	941	484	189	673	484	189	673
Annual aMW		**686**	**313**	**1,000**	**568**	**250**	**818**	**555**	**248**	**802**
2020	Jan	758	355	1,113	612	257	869	444	181	625
	Feb	803	365	1,168	689	321	1,010	689	321	1,010
	Mar	820	282	1,103	595	234	828	595	234	828
	Apr	1,072	426	1,498	761	290	1,051	761	290	1,051
	May	931	454	1,385	877	332	1,209	877	332	1,209
	June	1,010	431	1,441	704	335	1,039	704	335	1,039
	July	551	292	843	520	283	803	520	283	803
	Aug	467	251	717	437	243	680	437	243	680
	Sept	581	241	822	468	234	702	468	234	702
	Oct	414	216	629	391	206	597	391	206	597
	Nov	338	197	536	348	181	528	348	181	528
	Dec	584	374	958	486	190	675	486	190	675
Annual aMW		**694**	**324**	**1,018**	**574**	**259**	**833**	**560**	**252**	**812**

*HCC=Hells Canyon Complex, **ROR=Run of River

		50th Percentile			70th Percentile			90th Percentile		
Year	**Month**	**HCC***	**ROR****	**Total**	**HCC**	**ROR**	**Total**	**HCC**	**ROR**	**Total**
2021	Jan	760	355	1,115	613	257	870	446	182	628
	Feb	803	365	1,168	690	320	1,010	690	320	1,010
	Mar	824	283	1,107	602	235	837	602	235	837
	Apr	1,084	428	1,512	769	292	1,061	769	292	1,061
	May	946	455	1,401	882	334	1,216	882	334	1,216
	June	1,024	432	1,456	708	336	1,044	708	336	1,044
	July	551	292	843	520	284	804	520	284	804
	Aug	467	251	718	438	244	682	438	244	682
	Sept	584	241	826	470	234	704	470	234	704
	Oct	415	216	631	390	207	597	390	207	597
	Nov	337	198	535	348	181	529	348	181	529
	Dec	585	376	961	487	190	677	487	190	677
Annual aMW		**698**	**324**	**1,023**	**576**	**259**	**836**	**562**	**253**	**816**
2022	Jan	760	355	1,115	613	260	873	446	182	628
	Feb	803	366	1,168	690	320	1,010	690	320	1,010
	Mar	824	284	1,107	602	235	837	602	235	837
	Apr	1,085	428	1,513	770	295	1,065	770	295	1,065
	May	946	458	1,404	882	336	1,217	882	336	1,217
	June	1,025	435	1,461	710	336	1,046	710	336	1,046
	July	551	292	843	520	284	804	520	284	804
	Aug	467	251	718	438	244	681	438	244	681
	Sept	585	241	826	470	234	704	470	234	704
	Oct	415	216	630	390	207	597	390	207	597
	Nov	337	198	535	347	181	528	347	181	528
	Dec	586	378	964	487	190	677	487	190	677
Annual aMW		**698**	**325**	**1,024**	**576**	**260**	**837**	**563**	**254**	**816**

Year	Month	50th Percentile HCC*	ROR**	Total	70th Percentile HCC	ROR	Total	90th Percentile HCC	ROR	Total
2023	Jan	759	356	1,115	613	265	877	445	182	628
	Feb	802	366	1,168	689	320	1,009	689	320	1,009
	Mar	824	285	1,109	601	236	837	601	236	837
	Apr	1,084	428	1,513	769	298	1,068	769	298	1,068
	May	945	461	1,406	882	339	1,221	882	339	1,221
	June	1,032	441	1,472	711	338	1,049	711	338	1,049
	July	551	292	843	520	284	804	520	284	804
	Aug	467	251	718	437	244	681	437	244	681
	Sept	586	241	827	469	234	703	469	234	703
	Oct	415	216	631	390	207	597	390	207	597
	Nov	335	198	533	347	181	529	347	181	529
	Dec	586	380	966	487	190	678	487	190	678
Annual aMW		**699**	**326**	**1,025**	**576**	**261**	**838**	**562**	**254**	**817**
2024	Jan	759	357	1,116	613	271	884	445	182	627
	Feb	802	366	1,168	688	320	1,007	688	320	1,007
	Mar	824	286	1,110	601	236	837	601	236	837
	Apr	1,085	429	1,513	770	300	1,070	770	300	1,070
	May	947	463	1,409	882	341	1,223	882	341	1,223
	June	1,033	444	1,477	712	338	1,050	712	338	1,050
	July	550	292	842	519	284	803	519	284	803
	Aug	466	251	717	437	244	681	437	244	681
	Sept	586	241	828	468	234	703	468	234	703
	Oct	415	215	630	390	207	596	390	207	596
	Nov	335	198	533	348	181	529	348	181	529
	Dec	586	381	968	487	190	678	487	190	678
Annual aMW		**699**	**327**	**1,026**	**576**	**262**	**838**	**562**	**255**	**817**

		50th Percentile			70th Percentile			90th Percentile		
Year	**Month**	**HCC***	**ROR****	**Total**	**HCC**	**ROR**	**Total**	**HCC**	**ROR**	**Total**
2025	Jan	759	356	1,115	612	268	880	444	182	627
	Feb	800	366	1,165	688	319	1,007	688	319	1,007
	Mar	823	286	1,109	600	235	835	600	235	835
	Apr	1,084	428	1,512	768	300	1,068	768	300	1,068
	May	946	462	1,409	882	341	1,223	882	341	1,223
	June	1,032	443	1,475	711	337	1,049	711	337	1,049
	July	550	292	842	519	284	803	519	284	803
	Aug	466	251	716	436	244	680	436	244	680
	Sept	584	241	825	467	234	701	467	234	701
	Oct	414	215	630	389	206	596	389	206	596
	Nov	336	198	534	348	181	529	348	181	529
	Dec	586	380	966	486	190	677	486	190	677
Annual aMW		**698**	**327**	**1,025**	**576**	**262**	**837**	**562**	**255**	**816**
2026	Jan	758	355	1,113	611	265	877	444	182	626
	Feb	797	365	1,162	687	319	1,006	687	319	1,006
	Mar	822	286	1,108	599	234	833	599	234	833
	Apr	1,083	428	1,511	769	300	1,068	769	300	1,068
	May	946	462	1,408	882	341	1,222	882	341	1,222
	June	1,032	443	1,474	711	337	1,048	711	337	1,048
	July	549	292	841	519	284	802	519	284	802
	Aug	465	251	716	436	244	680	436	244	680
	Sept	582	241	823	466	234	700	466	234	700
	Oct	413	215	628	389	206	596	389	206	596
	Nov	337	198	534	348	181	529	348	181	529
	Dec	584	378	962	485	190	675	485	190	675
Annual aMW		**697**	**326**	**1,023**	**575**	**261**	**836**	**561**	**254**	**815**

		50th Percentile			70th Percentile			90th Percentile		
Year	**Month**	**HCC***	**ROR****	**Total**	**HCC**	**ROR**	**Total**	**HCC**	**ROR**	**Total**
2027	Jan	757	354	1,111	611	262	872	443	181	625
	Feb	792	364	1,156	685	318	1,003	685	318	1,003
	Mar	821	284	1,106	599	234	832	599	234	832
	Apr	1,082	427	1,509	767	299	1,066	767	299	1,066
	May	946	461	1,407	882	340	1,222	882	340	1,222
	June	1,031	441	1,472	710	337	1,047	710	337	1,047
	July	549	292	840	518	283	801	518	283	801
	Aug	465	251	715	435	243	679	435	243	679
	Sept	579	241	820	464	234	698	464	234	698
	Oct	412	215	627	390	206	596	390	206	596
	Nov	337	198	535	347	181	528	347	181	528
	Dec	583	376	959	485	190	675	485	190	675
Annual aMW		**696**	**325**	**1,021**	**574**	**261**	**835**	**560**	**254**	**814**
2028	Jan	756	353	1,109	610	258	868	443	181	623
	Feb	789	362	1,151	684	316	1,000	684	316	1,000
	Mar	820	283	1,102	598	232	830	598	232	830
	Apr	1,082	427	1,509	767	298	1,065	767	298	1,065
	May	945	460	1,404	882	339	1,221	882	339	1,221
	June	1,030	440	1,470	709	337	1,046	709	337	1,046
	July	548	291	840	517	283	800	517	283	800
	Aug	464	250	714	435	243	678	435	243	678
	Sept	576	241	817	463	234	697	463	234	697
	Oct	411	215	626	389	206	595	389	206	595
	Nov	338	198	536	347	181	528	347	181	528
	Dec	581	373	953	483	189	673	483	189	673
Annual aMW		**695**	**324**	**1,019**	**574**	**260**	**833**	**560**	**253**	**813**

		50th Percentile			70th Percentile			90th Percentile		
Year	**Month**	**HCC***	**ROR****	**Total**	**HCC**	**ROR**	**Total**	**HCC**	**ROR**	**Total**
2029	Jan	755	352	1,107	609	253	861	441	180	621
	Feb	786	360	1,146	683	314	997	683	314	997
	Mar	819	281	1,100	596	230	826	596	230	826
	Apr	1,081	426	1,507	767	298	1,065	767	298	1,065
	May	944	456	1,400	881	338	1,219	881	338	1,219
	June	1,029	439	1,468	708	336	1,044	708	336	1,044
	July	548	291	839	517	283	800	517	283	800
	Aug	463	250	713	434	243	677	434	243	677
	Sept	573	240	813	461	233	694	461	233	694
	Oct	410	215	625	389	206	595	389	206	595
	Nov	339	197	537	347	181	528	347	181	528
	Dec	579	370	949	482	189	671	482	189	671
Annual aMW		**694**	**323**	**1,017**	**573**	**259**	**831**	**559**	**253**	**812**
2030	Jan	753	351	1,104	606	247	853	441	178	619
	Feb	783	359	1,141	682	312	994	682	312	994
	Mar	817	280	1,097	596	227	823	596	227	823
	Apr	1,079	426	1,505	766	297	1,063	766	297	1,063
	May	944	455	1,399	881	331	1,212	881	331	1,212
	June	1,026	436	1,462	707	335	1,041	707	335	1,041
	July	547	291	838	516	283	799	516	283	799
	Aug	463	250	712	434	243	676	434	243	676
	Sept	569	240	809	459	233	692	459	233	692
	Oct	410	215	625	390	206	595	390	206	595
	Nov	341	197	538	347	181	527	347	181	527
	Dec	577	366	943	481	189	670	481	189	670
Annual aMW		**692**	**322**	**1,014**	**572**	**257**	**829**	**558**	**251**	**809**

		50th Percentile			70th Percentile			90th Percentile		
Year	**Month**	**HCC***	**ROR****	**Total**	**HCC**	**ROR**	**Total**	**HCC**	**ROR**	**Total**
2031	Jan	752	349	1,101	601	241	842	440	177	617
	Feb	781	359	1,140	680	308	988	680	308	988
	Mar	816	279	1,095	595	225	819	595	225	819
	Apr	1,078	425	1,503	765	297	1,062	765	297	1,062
	May	944	454	1,398	881	332	1,212	881	332	1,212
	June	1,022	434	1,455	706	335	1,040	706	335	1,040
	July	546	291	837	515	283	798	515	283	798
	Aug	462	250	712	433	242	675	433	242	675
	Sept	566	240	806	453	232	686	453	232	686
	Oct	411	214	626	390	205	596	390	205	596
	Nov	340	197	536	346	180	527	346	180	527
	Dec	575	363	937	480	189	668	480	189	668
Annual aMW		**691**	**321**	**1,012**	**570**	**256**	**826**	**557**	**250**	**807**
2032	Jan	750	348	1,098	600	236	835	440	177	617
	Feb	779	358	1,136	679	306	985	679	306	985
	Mar	815	278	1,093	593	224	817	593	224	817
	Apr	1,077	424	1,501	765	295	1,060	765	295	1,060
	May	943	453	1,396	880	332	1,212	880	332	1,212
	June	1,017	432	1,448	705	335	1,040	705	335	1,040
	July	546	291	836	515	282	797	515	282	797
	Aug	462	249	711	432	242	674	432	242	674
	Sept	562	240	802	452	232	684	452	232	684
	Oct	413	214	627	390	205	595	390	205	595
	Nov	340	196	536	346	180	526	346	180	526
	Dec	573	359	931	478	189	667	478	189	667
Annual aMW		**690**	**320**	**1,010**	**569**	**255**	**824**	**556**	**250**	**806**

Year	Month	50th Percentile			70th Percentile			90th Percentile		
		HCC*	ROR**	Total	HCC	ROR	Total	HCC	ROR	Total
2033	Jan	749	347	1,096	599	230	829	438	177	615
	Feb	777	357	1,133	677	305	982	677	305	982
	Mar	814	277	1,090	592	223	815	592	223	815
	Apr	1,076	424	1,499	763	293	1,056	763	293	1,056
	May	942	452	1,395	880	330	1,210	880	330	1,210
	June	1,012	430	1,443	704	334	1,038	704	334	1,038
	July	545	291	836	514	282	796	514	282	796
	Aug	461	249	710	432	242	674	432	242	674
	Sept	558	240	798	450	232	682	450	232	682
	Oct	414	214	628	390	205	595	390	205	595
	Nov	341	196	537	346	180	526	346	180	526
	Dec	572	355	927	475	188	664	475	188	664
Annual aMW		**688**	**319**	**1,008**	**568**	**254**	**822**	**555**	**249**	**804**
2034	Jan	748	346	1,093	598	225	823	437	177	613
	Feb	775	356	1,131	676	304	980	676	304	980
	Mar	813	274	1,087	590	222	812	590	222	812
	Apr	1,074	423	1,497	763	291	1,053	763	291	1,053
	May	941	451	1,393	879	329	1,209	879	329	1,209
	June	1,011	429	1,440	702	334	1,036	702	334	1,036
	July	544	290	835	514	282	795	514	282	795
	Aug	460	249	709	431	242	673	431	242	673
	Sept	554	239	794	448	231	679	448	231	679
	Oct	416	214	630	391	205	596	391	205	596
	Nov	341	196	537	345	180	525	345	180	525
	Dec	571	350	921	473	188	661	473	188	661
Annual aMW		**687**	**318**	**1,005**	**567**	**253**	**820**	**554**	**249**	**803**

Year	Month	50th Percentile HCC*	ROR**	Total	70th Percentile HCC	ROR	Total	90th Percentile HCC	ROR	Total
2035	Jan	746	344	1,091	598	219	817	436	176	612
	Feb	768	354	1,121	674	303	977	674	303	977
	Mar	811	273	1,084	589	221	809	589	221	809
	Apr	1,072	422	1,494	762	289	1,051	762	289	1,051
	May	941	450	1,391	879	329	1,208	879	329	1,208
	June	1,011	429	1,439	701	333	1,034	701	333	1,034
	July	544	290	834	513	282	794	513	282	794
	Aug	460	249	708	430	241	672	430	241	672
	Sept	550	239	789	446	231	677	446	231	677
	Oct	419	213	632	390	205	595	390	205	595
	Nov	340	195	535	345	180	525	345	180	525
	Dec	571	346	917	471	188	659	471	188	659
Annual aMW		**686**	**317**	**1,003**	**566**	**252**	**818**	**553**	**248**	**801**
2036	Jan	745	344	1,089	594	217	811	434	176	610
	Feb	765	351	1,117	673	301	975	673	301	975
	Mar	810	272	1,082	588	220	807	588	220	807
	Apr	1,072	421	1,493	761	288	1,048	761	288	1,048
	May	940	450	1,390	879	326	1,205	879	326	1,205
	June	1,009	427	1,437	699	333	1,032	699	333	1,032
	July	543	290	833	512	281	794	512	281	794
	Aug	459	248	707	430	241	671	430	241	671
	Sept	546	239	785	444	230	675	444	230	675
	Oct	420	213	633	390	204	595	390	204	595
	Nov	340	195	535	345	180	525	345	180	525
	Dec	570	341	911	471	188	658	471	188	658
Annual aMW		**685**	**316**	**1,001**	**565**	**251**	**816**	**552**	**247**	**800**

		50th Percentile			70th Percentile			90th Percentile		
Year	**Month**	**HCC***	**ROR****	**Total**	**HCC**	**ROR**	**Total**	**HCC**	**ROR**	**Total**
2037	Jan	743	343	1,086	592	215	806	433	175	608
	Feb	765	350	1,115	672	299	971	672	299	971
	Mar	809	270	1,079	585	217	802	585	217	802
	Apr	1,069	420	1,489	760	287	1,047	760	287	1,047
	May	940	449	1,388	879	326	1,204	879	326	1,204
	June	1,008	424	1,432	698	333	1,030	698	333	1,030
	July	542	290	832	511	281	793	511	281	793
	Aug	458	248	707	429	241	670	429	241	670
	Sept	544	239	783	442	230	672	442	230	672
	Oct	419	213	632	391	204	595	391	204	595
	Nov	340	194	534	346	179	525	346	179	525
	Dec	568	336	905	469	187	656	469	187	656
Annual aMW		**684**	**315**	**999**	**564**	**250**	**814**	**551**	**247**	**798**
2038	Jan	738	342	1,079	591	203	794	432	175	607
	Feb	762	351	1,113	670	295	964	670	295	964
	Mar	808	269	1,077	584	211	795	584	211	795
	Apr	1,067	419	1,487	759	286	1,045	759	286	1,045
	May	940	447	1,387	879	325	1,203	879	325	1,203
	June	1,023	423	1,445	696	332	1,029	696	332	1,029
	July	542	289	831	511	281	792	511	281	792
	Aug	458	248	706	428	241	669	428	241	669
	Sept	543	239	782	440	229	669	440	229	669
	Oct	418	213	631	391	204	594	391	204	594
	Nov	339	195	534	346	179	525	346	179	525
	Dec	568	331	899	468	187	655	468	187	655
Annual aMW		**684**	**314**	**997**	**564**	**248**	**811**	**550**	**245**	**796**

Long-Term Capacity Expansion Results (MW)

	Portfolio 1				Portfolio 13				
Gas Assumption:	Planning Gas Price				Planning Gas Price				
Carbon Assumption:	No Carbon Requirement				No Carbon Requirement				
B2H Assumption:	No B2H				B2H in Service 2026				
	Gas	**Solar**	**Battery**	**Coal Exit**	**Gas**	**Solar**	**Battery**	**Coal Exit**	**B2H**
2019				(127)				(127)	
2020				(58)				(58)	
2021									
2022		120		(177)				(177)	
2023		100							
2024									
2025		40	30	(133)				(133)	
2026	56								500
2027	111								
2028									
2029		80	20						
2030		40	20						
2031	300								
2032	111								
2033									
2034				(531)	300			(531)	
2035	522				300	80	50		
2036						80	20		
2037									
2038	56				300				
Nameplate Total (MW)	1,155	380	70	(1,026)	900	160	70	(1,026)	500
Net Build	579				604				

	Portfolio 2				Portfolio 14					
Gas Assumption:	Planning Gas Price				Planning Gas Price					
Carbon Assumption:	Planning Carbon Requirement				Planning Carbon Requirement					
B2H Assumption:	No B2H				B2H in Service 2026					
	Gas	**Solar**	**Battery**	**Coal Exit**	**Gas**	**Solar**	**Battery**	**Demand Response**	**Coal Exit**	**B2H**
2019				(127)					(127)	
2020				(58)					(58)	
2021										
2022		120		(177)		120			(177)	
2023		100				100				
2024										
2025				(133)					(133)	
2026		80	50					5	(174)	500
2027		80	20							
2028	300				111					
2029								5		
2030	300			(177)	111			5		
2031								5		
2032								5		
2033	300			(354)				5		
2034	56					45	30	5	(357)	
2035	111				300	40	20	5		
2036								5		
2037	300					40	10			
2038					300			5		
Nameplate Total (MW)	1,367	380	70	(1,026)	822	345	60	50	(1,026)	500
Net Build	791				751					

	Portfolio 3						**Portfolio 15**						
Gas Assumption:	Planning Gas Price						Planning Gas Price						
Carbon Assumption:	Generational Carbon Requirement						Generational Carbon Requirement						
B2H Assumption:	No B2H						B2H in Service 2026						
	Gas	**Wind**	**Solar**	**Battery**	**Demand Response**	**Coal Exit**	**Gas**	**Wind**	**Solar**	**Battery**	**Demand Response**	**Coal Exit**	**B2H**
2019						(127)						(127)	
2020						(58)						(58)	
2021													
2022			240	30		(177)			200			(177)	
2023			180	20	5				140		5		
2024		100			5	(180)		100	160		5		
2025		100	600	20	5	(133)		100	160		5	(133)	
2026		100	80	30	5		111	100	40		5	(354)	500
2027		100	80					100			5		
2028	300	100				(177)	300				5	(177)	
2029	300	100				(174)			240	30	5		
2030					5			100			5		
2031			5		5				120	10	5		
2032	300				5								
2033					5								
2034													
2035	111							100					
2036													
2037	56				5		56		40	20			
2038	111				5				80	20	5		
Nameplate Total (MW)	1,178	600	1,185	100	50	(1,026)	467	600	1,180	80	50	(1,026)	500
Net Build	2,087						1,851						

	Portfolio 4						Portfolio 16						
Gas Assumption:	Planning Gas Price						Planning Gas Price						
Carbon Assumption:	High Carbon Requirement						High Carbon Requirement						
B2H Assumption:	No B2H						B2H in Service 2026						
	Gas	**Wind**	**Solar**	**Battery**	**Demand Response**	**Coal Exit**	**Gas**	**Wind**	**Solar**	**Battery**	**Demand Response**	**Coal Exit**	**B2H**
2019						(127)						(127)	
2020						(58)						(58)	
2021													
2022			120			(177)			120			(177)	
2023			100		5				100		5		
2024	300				5	(180)	56				5	(180)	
2025			160	30	5	(133)	111		40		5	(133)	
2026	111	100	240	30	5	(174)					5	(174)	500
2027		100	160	20	5			100	160		5		
2028	300	100	40			(177)	300	100				(177)	
2029		100	360					100	80				
2030		100	5					100	45	30			
2031		100			5			100	365	30			
2032			5		5			100	40	10			
2033					5				40				
2034	111				5						5		
2035											5		
2036	56										5		
2037	56								160	10	5		
2038	56				5				40		5		
Nameplate Total (MW)	989	600	1,190	80	50	(1,026)	467	600	1,190	80	50	(1,026)	500
Net Build	1,883						1,861						

	Portfolio 5					Portfolio 17					
Gas Assumption:	Mid-Level Gas Price					Mid-Level Gas Price					
Carbon Assumption:	No Carbon Requirement					No Carbon Requirement					
B2H Assumption:	No B2H					B2H in Service 2026					
	Gas	**Solar**	**Battery**	**Demand Response**	**Coal Exit**	**Gas**	**Solar**	**Battery**	**Demand Response**	**Coal Exit**	**B2H**
2019					(127)					(127)	
2020					(58)					(58)	
2021											
2022										(177)	
2023		100		5					5		
2024				5							
2025				5	(133)					(133)	
2026				5							500
2027		40	30	5							
2028		40	20	5							
2029	111			5							
2030				5							
2031		80	20	5							
2032		85	10	5							
2033	56										
2034	300				(708)		40	20	5	(531)	
2035	637					467	120	50	5		
2036						56			5		
2037	111					300			5		
2038									5		
Nameplate Total (MW)	1,214	345	80	50	(1,026)	822	160	70	30	(1,026)	500
Net Build	663					556					

	Portfolio 6					Portfolio 18					
Gas Assumption:	Mid-Level Gas Price					Mid-Level Gas Price					
Carbon Assumption:	Planning Carbon Requirement					Planning Carbon Requirement					
B2H Assumption:	No B2H					B2H in Service 2026					
	Gas	**Solar**	**Battery**	**Demand Response**	**Coal Exit**	**Gas**	**Solar**	**Battery**	**Demand Response**	**Coal Exit**	**B2H**
2019					(127)					(127)	
2020					(58)					(58)	
2021											
2022		120			(177)					(177)	
2023		100									
2024				5							
2025				5	(133)					(133)	
2026		120	40	5							500
2027	111			5							
2028				5							
2029		80	30	5							
2030	300										
2031											
2032	111										
2033									5		
2034		40			(531)	300			5	(531)	
2035	470			5		300	80	20	5		
2036		80	10	5			80		5		
2037	56	40		5			40	30	5		
2038	56			5			80	20	5		
Nameplate Total (MW)	1,103	580	80	50	(1,026)	600	280	70	30	(1,026)	500
Net Build	787					454					

	Portfolio 7						Portfolio 19						
Gas Assumption:	Mid-Level Gas Price						Mid-Level Gas Price						
Carbon Assumption:	Generational Carbon Requirement						Generational Carbon Requirement						
B2H Assumption:	No B2H						B2H in Service 2026						
	Gas	**Wind**	**Solar**	**Battery**	**Demand Response**	**Coal Exit**	**Gas**	**Wind**	**Solar**	**Battery**	**Demand Response**	**Coal Exit**	**B2H**
2019						(127)						(127)	
2020						(58)						(58)	
2021													
2022		100	640	10		(177)		100	280	30		(177)	
2023		100	140	30	5				140		5		
2024		100	400	40	5	(180)		100			5	(180)	
2025	111	100			5	(133)		100			5	(133)	
2026	300	100			5	(174)		100			5	(174)	500
2027					5			100			5		
2028	300				5	(177)		100			5		
2029		100			5		300				5	(177)	
2030			5						400		5		
2031			5						120		5		
2032					5		300				5		
2033	300								40	10			
2034									120	20			
2035	56								85	20			
2036													
2037	56												
2038													
Nameplate Total (MW)	1,122	600	1,190	80	40	(1,026)	600	600	1,185	80	50	(1,026)	500
Net Build	2,006						1,989						

	Portfolio 8						Portfolio 20						
Gas Assumption:	Mid-Level Gas Price						Mid-Level Gas Price						
Carbon Assumption:	High Carbon Requirement						High Carbon Requirement						
B2H Assumption:	No B2H						B2H in Service 2026						
	Gas	**Wind**	**Solar**	**Battery**	**Demand Response**	**Coal Exit**	**Gas**	**Wind**	**Solar**	**Battery**	**Demand Response**	**Coal Exit**	**B2H**
2019						(127)						(127)	
2020						(58)						(58)	
2021													
2022			160	30		(177)						(177)	
2023		100	140		5			100	180				
2024	300				5	(180)		100					
2025		100	440	20	5	(133)		100				(133)	
2026		100	325	10	5	(174)						(174)	500
2027	300	100	40		5		300					(180)	
2028		100	40	10	5	(177)		100	240	40		(177)	
2029		100			5			100	40				
2030	300				5			100	405	10			
2031			40	10					45				
2032			5						40				
2033									40	10	5		
2034											5		
2035											5		
2036							300				5		
2037	167										5		
2038					5		300				5		
Nameplate Total (MW)	1,067	600	1,190	80	45	(1,026)	900	600	990	60	30	(1,026)	500
Net Build	1,956						2,054						

	Portfolio 9						Portfolio 21						
Gas Assumption:	High Gas Price						High Gas Price						
Carbon Assumption:	Zero Carbon Requirement						Zero Carbon Requirement						
B2H Assumption:	No B2H						B2H in Service 2026						
	Gas	**Wind**	**Solar**	**Battery**	**Demand Response**	**Coal Exit**	**Gas**	**Wind**	**Solar**	**Battery**	**Demand Response**	**Coal Exit**	**B2H**
2019						(127)						(127)	
2020						(58)						(58)	
2021													
2022													
2023			100										
2024			40								5		
2025			40	20		(133)					5	(133)	
2026			40	10							5		500
2027			200	10							5		
2028			40	10							5		
2029			200								5		
2030									80		5		
2031	300								120		5		
2032								100	200		5		
2033			120					100	200	10			
2034	300					(708)	56	100	120	10		(708)	
2035	637		40				356	100	205				
2036								100	40	10			
2037	111						300	100					
2038	111						222				5		
Nameplate Total (MW)	1,459		820	50		(1,026)	933	600	965	30	50	(1,026)	500
Net Build	1,303						2,052						

	Portfolio 10						Portfolio 22						
Gas Assumption:	High Gas Price						High Gas Price						
Carbon Assumption:	Planning Carbon Requirement						Planning Carbon Requirement						
B2H Assumption:	No B2H						B2H in Service 2026						
	Gas	**Wind**	**Solar**	**Battery**	**Demand Response**	**Coal Exit**	**Gas**	**Wind**	**Solar**	**Battery**	**Demand Response**	**Coal Exit**	**B2H**
2019						(127)						(127)	
2020						(58)						(58)	
2021													
2022													
2023			100								5		
2024			40	30							5		
2025			80	30		(133)					5	(133)	
2026			160	20							5		500
2027			320								5		
2028			120								5		
2029			40								5		
2030		100	5						80		5		
2031		100						100	480		5		
2032		100	205					100	80	20	5		
2033	111				5			100	120	30			
2034	300	100			5	(708)		100	80	20		(708)	
2035	467	100			5		411	100	85				
2036	300	100			5			100					
2037					5		300						
2038					5				40	10			
Nameplate Total (MW)	1,178	600	1,070	80	30	(1,026)	711	600	965	80	50	(1,026)	500
Net Build	1,932						1,880						

	Portfolio 11							Portfolio 23						
Gas Assumption:	High Gas Price							High Gas Price						
Carbon Assumption:	Generational Carbon Requirement							Generational Carbon Requirement						
B2H Assumption:	No B2H							B2H in Service 2026						
	Gas	**Wind**	**Solar**	**Battery**	**Biomass**	**Demand Response**	**Coal Exit**	**Gas**	**Wind**	**Solar**	**Battery**	**Demand Response**	**Coal Exit**	**B2H**
2019							(127)						(127)	
2020							(58)						(58)	
2021														
2022		100	640	30			(177)							
2023		100	260			5								
2024		200	280	50		5	(180)							
2025		200				5	(133)						(133)	
2026	300	200	5			5	(174)						(174)	500
2027		200				5								
2028	300					5	(177)		200	480	30		(177)	
2029						5			200	360	60			
2030						5			200	40				
2031			5		30	5			200					
2032					30				200					
2033				10	30				100			5		
2034		100		5	30							5	(357)	
2035	300	100						300				5		
2036								300				5		
2037					30							5		
2038	111			10		5		300				5		
Nameplate Total (MW)	1,011	1,200	1,190	105	150	50	(1,026)	900	1,100	880	90	30	(1,026)	500
Net Build	2,680							2,474						

	Portfolio 12								Portfolio 24						
Gas Assumption:	High Gas Price								High Gas Price						
Carbon Assumption:	High Carbon Requirement								High Carbon Requirement						
B2H Assumption:	No B2H								B2H in Service 2026						
	Gas	**Wind**	**Solar**	**Battery**	**PS Hydro***	**Biomass**	**Demand Response**	**Coal Exit**	**Gas**	**Wind**	**Solar**	**Battery**	**Demand Response**	**Coal Exit**	**B2H**
2019								(127)						(127)	
2020								(58)						(58)	
2021															
2022		100	520	30				(177)		100	520	30		(177)	
2023		100	340							100	100				
2024			160	35						200	320	20	5	(180)	
2025		100	85	10				(313)		200			5	(133)	
2026		200	40		500			(174)		100	40		5	(174)	500
2027		200								200			5		
2028		100		5		30		(177)	300				5	(177)	
2029										100					
2030	300								111		5				
2031											80	30			
2032		200	40	10		30									
2033		100				30									
2034															
2035		100	5				5						5		
2036									300				5		
2037						30					85	10	5		
2038	411												5		
Nameplate Total (MW)	711	1,200	1,190	90	500	120	5	(1,026)	711	1,000	1,150	90	45	(1,026)	500
Net Build	2,790								2,470						

* PS = Pumped Storage

Oregon Carbon Emission Forecast

Idaho Power anticipates the 2019 IRP carbon emission forecast will be used to establish a target for Idaho Power compliance with the proposed Oregon Cap and Trade Legislation. Idaho Power carefully reviewed historical emissions and emissions assumptions in the portfolio modeling and output.

The Total Carbon Dioxide (CO_2) Emissions forecast is composed of results from the AURORA modeling, policy adjustments to IRP forecast assumptions and a Market Volatility adjustment. The modeled AURORA resource dispatch from Idaho Power's preferred resource portfolio, Portfolio 14, is the basis for the emissions forecast. The AURORA emissions forecast consists of the emissions from the modeled operation of Idaho Power's resources and emissions based on forecasted purchased energy. Emissions from forecasted purchased energy is estimated to contribute 0.47 short tons per MWh, which is in-line with the unspecified market purchases used by the California Air Resource Board in their Cap and Trade program.

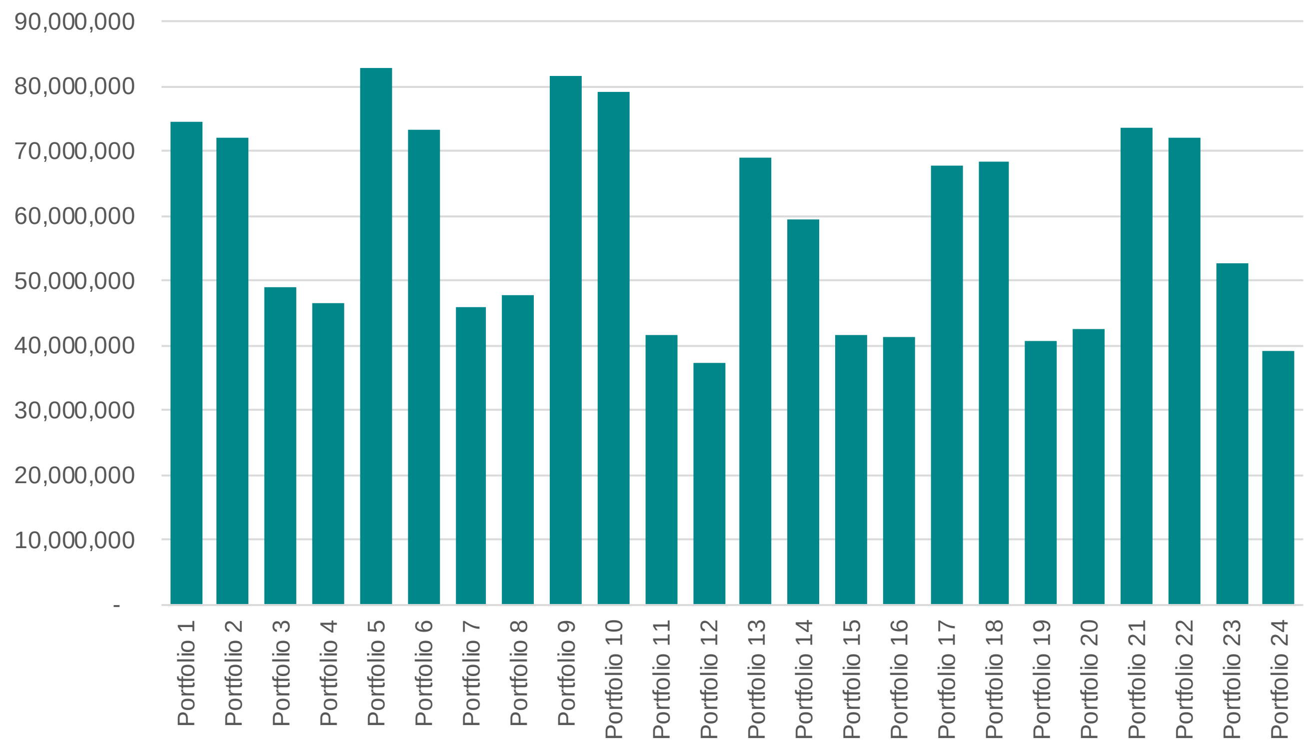
The hydro forecast in the 2019 IRP AURORA modeling assumes future increases in hydro generation based on expansion of Idaho Power's cloud seeding program and certain State of Idaho groundwater management activities. The actual results from these hydro generation programs may not result in the forecasted increase in generation. Cloud seeding expansion is subject to regulatory review and funding and therefore, was removed from carbon forecast modeling. Groundwater management activities, such as managed aquifer recharge has exceeded the State of Idaho's goals in 2017 and 2018, resulting in reduced wintertime hydro generation production. Idaho Power is concerned that trend may continue and thus feels that carbon forecast modeling should use a more conservative hydrogeneration assumption.

Lastly, Idaho Power reviewed recent system operations, resource dispatch and associated carbon emissions as well as the near-term operational forecasts. This review resulted in an Market Forecast Volatility adjustment to reconcile the discrepancy in emissions forecasts between the IRP and near-term operational planning. Examples of events that may drive market volatility: unplanned system outages (Idaho Power's system and surrounding system), extreme weather events, supply interruptions or limitations, natural disaster, etc.

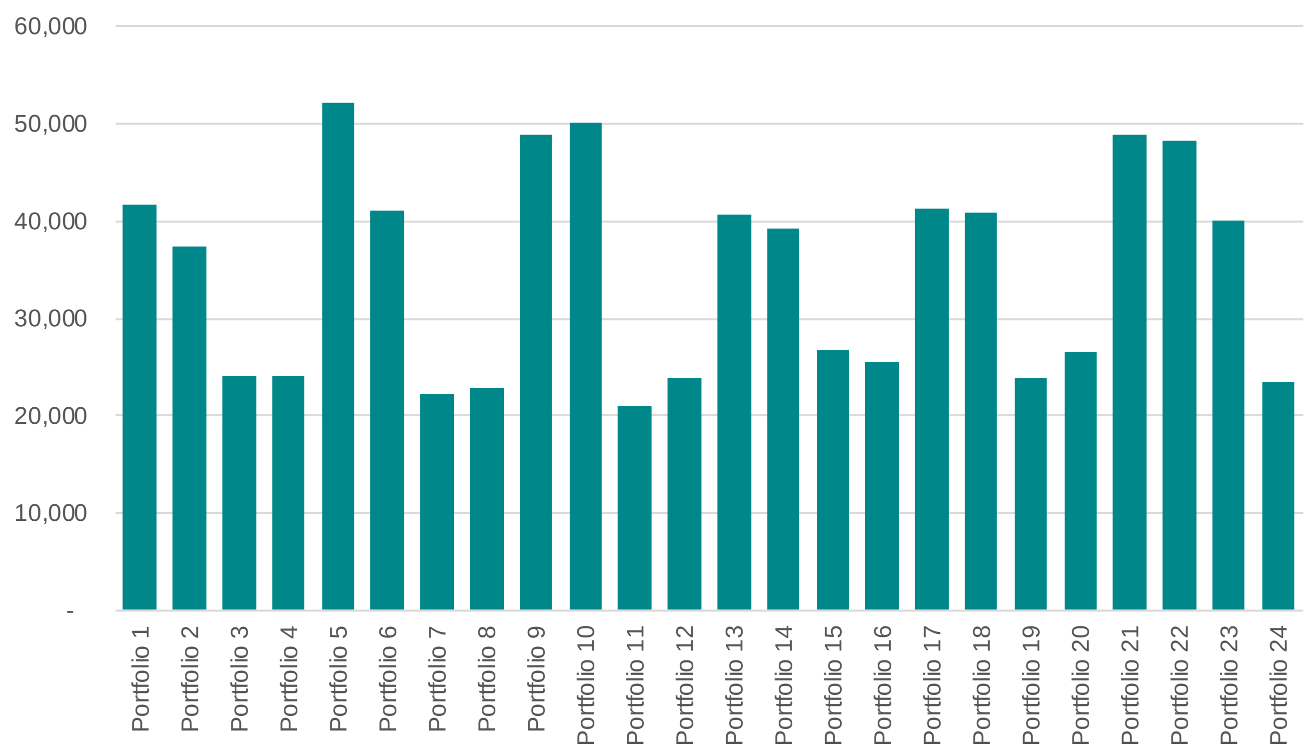
Year	Resource CO_2 Emissions	Market Purchases CO^2	Hydro Policy Implementation Uncertainty Adjustment	Market Volatility Adjustment	Total System CO_2 Emissions	Oregon CO_2 Emissions
2019	3,533,079	448,533	329,686	664,389	4,975,686	226,911
2020	3,664,201	410,368	481,180	664,389	5,220,137	237,299
2021	3,594,249	530,053	541,259	664,389	5,329,949	241,528
2022	3,472,987	559,790	566,011	664,389	5,263,177	237,299
2023	3,408,897	591,857	586,927	664,389	5,252,070	235,644
2024	3,529,447	661,261	609,505	664,389	5,464,601	243,214
2025	3,763,577	646,810	617,935	664,389	5,692,711	252,276
2026	2,596,630	1,209,969	626,016	–	4,432,615	195,791
2027	3,001,743	1,095,735	631,418	–	4,728,897	208,289
2028	3,032,615	1,127,123	637,980	–	4,797,718	210,394
2029	3,040,079	1,255,798	643,882	–	4,939,759	215,587
2030	3,030,783	1,237,158	646,328	–	4,914,269	213,686
2031	3,007,281	1,492,658	651,605	–	5,151,544	223,234
2032	2,941,552	1,644,275	659,269	–	5,245,097	226,485
2033	2,984,273	1,712,284	672,911	–	5,369,468	231,260
2034	2,774,819	1,747,203	682,302	–	5,204,324	223,211
2035	1,835,535	1,569,586	693,035	–	4,098,156	174,828
2036	1,831,061	1,646,550	708,991	–	4,186,602	177,580
2037	1,858,076	1,804,875	687,647	–	4,350,598	183,483
2038	2,548,559	1,119,207	678,607	–	4,346,373	182,355

PORTFOLIO GENERATING RESOURCE EMISSIONS

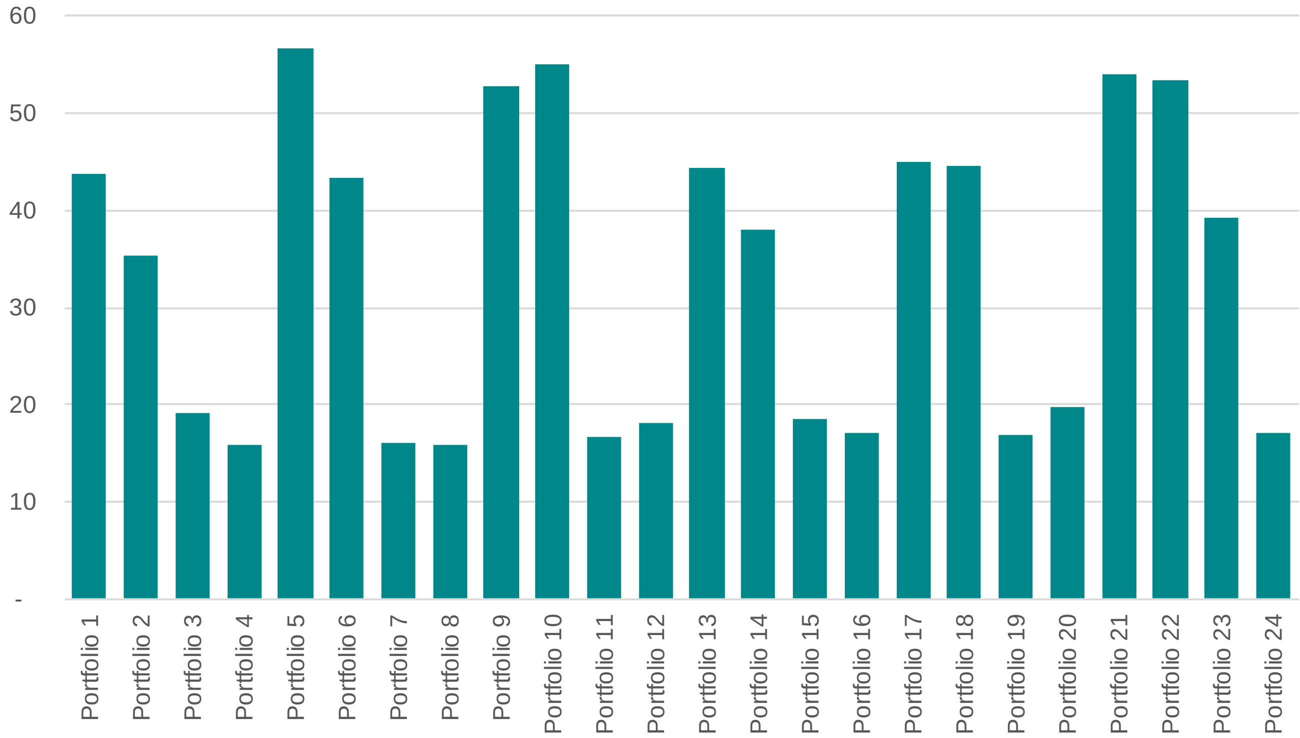
CO_2 Tons



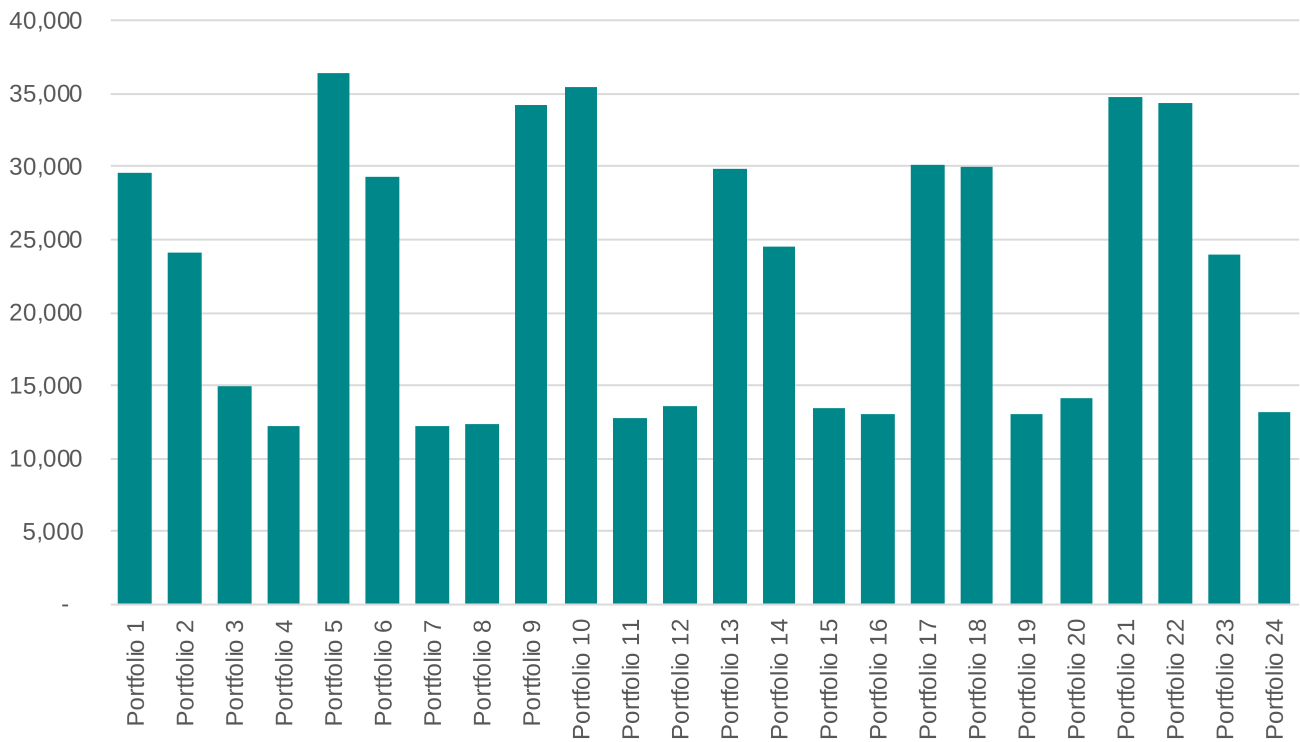
NOx Tons



HG Tons



SO_2 Tons



COMPLIANCE WITH STATE OF OREGON IRP GUIDELINES

Compliance with State of Oregon EV Guidelines

Guideline 1: Substantive Requirements

a. All resources must be evaluation on a consistent and comparable basis.
   - All known resources for meeting the utility's load should be considered, including supply-side options which focus on the generation, purchase and transmission of power - or gas purchases, transportation, and storage - and demand side options which focus on conservation and demand response.
   - Utilities should compare different resource fuel types, technologies, lead times, in-service dates, durations and locations in portfolio risk modeling.
   - Consistent assumptions and methods should be used for evaluation of all resources.
   - The after-tax marginal weighted-average cost of capital (WACC) should be used to discount all future resource costs.

Idaho Power response:

Supply-side and purchased resources for meeting the utility's load are discussed in *Chapter 3. Idaho Power Today;* demand-side options are discussed in *Chapter 5. Demand-Side Resources*; and transmission resources are discussed in *Chapter 6. Transmission Planning*.

New resource options including fuel types, technologies, lead times, in-service dates, durations and locations are described in *Chapter 4. Future Supply-side Generation and Storage Resources*, *Chapter 5. Demand-Side resources*, *Chapter 6. Transmission Planning*, and *Chapter 7. Planning Period Forecasts*.

The consistent modeling method for evaluating new resource options is described in *Chapter 7. Planning Period Forecasts—Resource Cost Analysis* and *Chapter 9. Modeling Analysis and Result—Planning Case Portfolio Analysis*.

The WACC rate used to discount all future resource costs is discussed in the Technical Appendix *Supply Side Resource Data – Key Financial and Forecast Assumptions*.

b. Risk and uncertainty must be considered.
   - At a minimum, utilities should address the following sources of risk and uncertainty:
     1. Electric utilities: load requirements, hydroelectric generation, plant forced outages, fuel prices, electricity prices, and costs to comply with any regulation of greenhouse gas emissions.
     2. Natural gas utilities: demand (peak, swing and baseload), commodity supply and price, transportation availability and price, and costs to comply with any regulation of greenhouse gas emissions.
   - Utilities should identify in their plans any additional sources of risk and uncertainty.

Idaho Power response:

Electric utility risk and uncertainty factors (load, natural gas, and water conditions) for resource portfolios are considered in *Chapter 9 Modeling Analysis*. Plant forced outages are modeled in AURORA on a unit basis and are discussed in *Chapter 9 Loss of Load Expectation*. Risk and uncertainty associated with high natural gas and high carbon cost are discussed in *Chapter 9 Portfolio Cost Analysis.*

Additional sources of risk and uncertainty including regional resource adequacy and qualitative risks are discussed in *Chapter 9. Modeling Analysis*.

c. The primary goal must be the selection of a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers.

- The planning horizon for analyzing resource choices should be at least 20 years and account for end effects. Utilities should consider all costs with a reasonable likelihood of being included in rates over the long term, which extends beyond the planning horizon and the life of the resource.
- Utilities should use present value of revenue requirement (PVRR) as the key cost metric. The plan should include analysis of current and estimated future costs for all long-lived resources such as power plants, gas storage facilities, and pipelines, as well as all short-lived resources such as gas supply and short-term power purchases.
- To address risk, the plan should include, at a minimum:
  a. Two measures of PVRR risk: one that measures the variability of costs and one that measures the severity of bad outcomes.
  b. Discussion of the proposed use and impact on costs and risks of physical and financial hedging.
- The utility should explain in its plan how its resource choices appropriately balance cost and risk.

Idaho Power response:

The IRP methodology and the planning horizon of 20 years are discussed in *Chapter 1. Summary—Introduction*.

Modeling analysis of current and estimated future costs for all long-lived resources such as power plants, gas storage facilities, and pipelines, as well as all short-lived resources such as gas supply and short-term power purchases is discussed in *Chapter 9. Modeling Analysis*.

The discussion of cost variability and extreme outcomes, including bad outcomes is discussed in *Chapter 9. Modeling Analysis*.

Idaho Power's Risk Management Policy regarding physical and financial hedging is discussed in *Chapter 1. IRP Methodology*. Idaho Power's Energy Risk Management Program is designed to systematically identify, quantify and manage the exposure of the company and its customers to the uncertainties related to the energy markets in which the Company is an active participant. The Company's Risk Management Standards limit term purchases to the prompt 18 months of the forward curve.

Idaho Power's plan and how the resource choices appropriately balance cost and risk is presented in *Chapter 10. Preferred Portfolio and Action Plan.*

d. The plan must be consistent with the long-run public interest as expressed in Oregon and federal energy policies.

Idaho Power response:
Long-run public interest issues are discussed in *Chapter 2. Political, Regulatory, and Operational Issues*.

Guideline 2: Procedural Requirements

a. The public, which includes other utilities, should be allowed significant involvement in the preparation of the IRP. Involvement includes opportunities to contribute information and ideas, as well as to receive information. Parties must have an opportunity to make relevant inquiries of the utility formulating the plan. Disputes about whether information requests are relevant or unreasonably burdensome, or whether a utility is being properly responsive, may be submitted to the Commission for resolution.

Idaho Power response:
The IRP Advisory Council meetings are open to the public. A roster of the IRP Advisory Council members along with meeting schedules and agendas is provided in the Technical Appendix, *IRP Advisory Council*.

b. While confidential information must be protected, the utility should make public, in its plan, any non-confidential information that is relevant to its resource evaluation and action plan. Confidential information may be protected through use of a protective order, through aggregation or shielding of data, or through any other mechanism approved by the Commission.

Idaho Power response:
Idaho Power makes public extensive information relevant to its resource evaluation and action plan. This information is discussed in IRP Advisory Council meetings and found throughout the 2019 IRP, the 2019 Load and Sales Forecast and in the 2019 Technical Appendix.

c. The utility must provide a draft IRP for public review and comment prior to filing a final plan with the Commission.

Idaho Power response:
Idaho Power provided copies to members of the IRPAC on Friday, June 7, 2019. The company requested for comments to be provided no later than Friday, June 14, 2019.

Guideline 3: Plan Filing, Review, and Updates

a. A utility must file an IRP within two years of its previous IRP acknowledgment order. If the utility does not intend to take any significant resource action for at least two years after its next IRP is due, the utility may request an extension of its filing date from the Commission.

Idaho Power response:
The OPUC acknowledged Idaho Power's 2017 IRP on May 23, 2018 in Order 18-176. The Idaho Power 2019 IRP will be filed by June 30, 2019.

b. The utility must present the results of its filed plan to the Commission at a public meeting prior to the deadline for written public comment.

Idaho Power response:
Idaho Power will schedule a public meeting at the OPUC following the June 28, 2019 filing of the 2019 IRP.

c. Commission staff and parties should complete their comments and recommendations within six months of IRP filing.

Idaho Power response:
No response needed.

d. The Commission will consider comments and recommendations on a utility's plan at a public meeting before issuing an order on acknowledgment. The Commission may provide the utility an opportunity to revise the plan before issuing an acknowledgment order.

Idaho Power response:
No response needed.

e. The Commission may provide direction to a utility regarding any additional analyses or actions that the utility should undertake in its next IRP.

Idaho Power response:
No response needed.

f. Each utility must submit an annual update on its most recently acknowledged plan. The update is due on or before the acknowledgment order anniversary date. Once a utility anticipates a significant deviation from its acknowledged IRP, it must file an update with the Commission, unless the utility is within six months of filing its next IRP. The utility must summarize the update at a Commission public meeting. The utility may request acknowledgment of changes in proposed actions identified in an update.

Idaho Power response:

Idaho Power submitted its annual update on January 28, 2019. A public meeting was held March 12, 2019 to discuss the 2017 IRP update.

g. Unless the utility requests acknowledgement of changes in proposed actions, the annual update is an informational filing that:
   - Describes what actions the utility has taken to implement the plan;
   - Provides an assessment of what has changed since the acknowledgment order that affects the action plan, including changes in such factors as load, expiration of resource contracts, supply-side and demand-side resource acquisitions, resource costs, and transmission availability; and
   - Justifies any deviations from the acknowledged action plan.

Idaho Power response:

No response needed.

Guideline 4: Plan Components

At a minimum, the plan must include the following elements:

a. An explanation of how the utility met each of the substantive and procedural requirements;

Idaho Power response:

Idaho Power provides information on how the company met each requirement in a table is presented in the Technical Appendix and will be provided to the OPUC staff in an informal letter.

b. Analysis of high and low load growth scenarios in addition to stochastic load risk analysis with an explanation of major assumptions;

Idaho Power response:

High-growth scenarios at the 90th and 95th percentile levels for peak hour, and at the 70th and 90th percentile levels for energy are provided in *Chapter 7. Planning Period Forecasts*. Stochastic load risk analysis and major assumptions are discussed in *Chapter 9. Modeling Analysis*. Major assumptions are also discussed in *Chapter 7. Planning Period Forecasts.*

c. For electric utilities, a determination of the levels of peaking capacity and energy capability expected for each year of the plan, given existing resources; identification of capacity and energy needed to bridge the gap between expected loads and resources; modeling of all existing transmission rights, as well as future transmission additions associated with the resource portfolios tested;

Idaho Power response:

Peaking capacity and energy capability for each year of the plan for existing resources is discussed in *Chapter 7. Planning Period Forecasts*. Detailed forecasts are provided in the Technical Appendix, *Sales and Load Forecast Data* and *Existing Resource Data*. Identification of capacity and energy needed to bridge the gap between expected loads and resources is discussed in *Chapter 8. Portfolios*.

d. For natural gas utilities, a determination of the peaking, swing and base-load gas supply and associated transportation and storage expected for each year of the plan, given existing resources; and identification of gas supplies (peak, swing and base-load), transportation and storage needed to bridge the gap between expected loads and resources;

Idaho Power response:

Not applicable.

e. Identification and estimated costs of all supply-side and demand-side resource options, taking into account anticipated advances in technology;

Idaho Power response:

Supply-side resources are discussed in *Chapter 4. Future Supply-Side Generation and Storage Resources*.

Demand-side resources are discussed in *Chapter 5-Demand-Side Resources*.

Resource costs are discussed in *Chapter 7. Planning Period Forecasts – Analysis of IRP Resource - Resource Costs-IRP Resources* and presented in the Technical Appendix, *Supply-Side Resource Data Levelized Cost of Energy*.

f. Analysis of measures the utility intends to take to provide reliable service, including cost-risk tradeoffs;

Idaho Power response:

Resource reliability is covered in *Chapter 9. Modeling Analysis*

g. Identification of key assumptions about the future (e.g., fuel prices and environmental compliance costs) and alternative scenarios considered;

Idaho Power response:

Key Assumptions including the natural gas price forecast are discussed in *Chapter 7. Planning Period Forecasts* and in the Technical Appendix, *Key Financial and Forecast Assumptions*. Environmental compliance costs are addressed in *Chapter 9. Modeling Analysis – Portfolio Emission Results* and in the Technical Appendix, *Portfolio Analysis, Results and supporting Documentation–Portfolio Emissions*.

h. Construction of a representative set of resource portfolios to test various operating characteristics, resource types, fuels and sources, technologies, lead times, in-service dates, durations and general locations – system-wide or delivered to a specific portion of the system;

Idaho Power response:
Resource portfolios considered for the 2019 IRP are described in *Chapter 8. Portfolios*.

i. Evaluation of the performance of the candidate portfolios over the range of identified risks and uncertainties;

Idaho Power response:
Evaluation of the portfolios over a range of risks and uncertainties is discussed in *Chapter 9. Modeling Analysis*.

j. Results of testing and rank ordering of the portfolios by cost and risk metric, and interpretation of those results;

Idaho Power response:
Portfolio cost, risk results, interpretations and the selection of the preferred portfolio are provided in *Chapter 9. Modeling Analysis*.

k. Analysis of the uncertainties associated with each portfolio evaluated;

Idaho Power response:
The quantitative and qualitative uncertainties associated with each portfolio are evaluated in *Chapter 9. Modeling Analysis*.

l. Selection of a portfolio that represents the best combination of cost and risk for the utility and its customers

Idaho Power response:
The preferred resource portfolio is identified in *Chapter 10. Preferred Portfolio and Action Plan*.

m. Identification and explanation of any inconsistencies of the selected portfolio with any state and federal energy policies that may affect a utility's plan and any barriers to implementation; and

Idaho Power response:

Risk associated with the selected portfolio including coal-unit exits is discussed in *Chapter 10. Preferred Portfolio and Action Plan*.

n. An action plan with resource activities the utility intends to undertake over the next two to four years to acquire the identified resources, regardless of whether the activity was acknowledged in a previous IRP, with the key attributes of each resource specified as in portfolio testing.

Idaho Power response:

An action plan is provided in *Chapter 1. Summary—Action Plan* and in *Chapter 10 Preferred Portfolio and Action Plan.*

Guideline 5: Transmission

Portfolio analysis should include costs to the utility for the fuel transportation and electric transmission required for each resource being considered. In addition, utilities should consider fuel transportation and electric transmission facilities as resource options, taking into account their value for making additional purchases and sales, accessing less costly resources in remote locations, acquiring alternative fuel supplies, and improving reliability.

Idaho Power response:

The fuel transportation for each resource being considered is presented in the Technical Appendix, *Cost Inputs and Operating Assumptions*. Transmission assumptions for supply-side resources considered are included in *Chapter 6. Transmission Planning—Transmission assumptions in IRP portfolios*. Transportation for natural gas is discussed in *Chapter 7. Planning Period Forecasts—Natural Gas Price Forecast*.

Guideline 6: Conservation

a. Each utility should ensure that a conservation potential study is conducted periodically for its entire service territory.

Idaho Power response:

The contractor-provided conservation potential study for the 2019 IRP and is described in *Chapter 5 Demand-Side Resources – Energy Efficiency Forecasting – Potential Assessment*.

b. To the extent that a utility controls the level of funding for conservation programs in its service territory, the utility should include in its action plan all best cost/risk portfolio conservation resources for meeting projected resource needs, specifying annual savings targets.

Idaho Power response:

A forecast for energy efficiency effects is provided in Cha*pter 5. Demand-Side Resources*.

c. To the extent that an outside party administers conservation programs in a utility's service territory at a level of funding that is beyond the utility's control, the utility should:
   - Determine the amount of conservation resources in the best cost/risk portfolio without regard to any limits on funding of conservation programs; and
   - Identify the preferred portfolio and action plan consistent with the outside party's projection of conservation acquisition.

Idaho Power response:

Idaho Power administers all its conservation programs except market transformation. Treatment of third party market transformation savings was provided by the Northwest Energy Efficiency Alliance (NEEA) and is discussed in *Appendix B: Idaho Power's Demand-Side Management 2017 Annual Report.* NEEA savings are included as savings to meet targets because of the overlap of NEEA initiatives and IPC's most recent potential study.

Guideline 7: Demand Response

Plans should evaluate demand response resources, including voluntary rate programs, on par with other options for meeting energy, capacity, and transmission needs (for electric utilities) or gas supply and transportation needs (for natural gas utilities).

Idaho Power response:

Demand response resources are evaluated in *Chapter 5. Demand-Side Resources – Changes from the 2017 IRP.*

Guideline 8: Environmental Costs

Utilities should include, in their base-case analyses, the regulatory compliance costs they expect for carbon dioxide (CO_2), nitrogen oxides, sulfur oxides, and mercury emissions. Utilities should analyze the range of potential CO_2 regulatory costs in Order No. 93-695, from zero to $40 (1990$). In addition, utilities should perform sensitivity analysis on a range of reasonably possible cost adders for nitrogen oxides, sulfur oxides, and mercury, if applicable.

Idaho Power response:

Compliance with existing environmental regulation and emissions for each portfolio are discussed in *Chapter 9. Modeling Analysis and Results—Qualitative Risk Analysis*. Emissions for each portfolio are shown in the Technical Appendix, *Portfolio Analysis, Results, and Supporting Documentation*.

Guideline 9: Direct Access Loads

An electric utility's load-resource balance should exclude customer loads that are effectively committed to service by an alternative electricity supplier.

Idaho Power response:

Idaho Power does not have any customers served by alternative electricity suppliers and Idaho Power has no direct access loads.

Guideline 10: Multi-state Utilities

Multi-state utilities should plan their generation and transmission systems, or gas supply and delivery, on an integrated-system basis that achieves a best cost/risk portfolio for all their retail customers.

Idaho Power response:

Idaho Power's analysis was performed on an integrated-system basis discussed in *Chapter 9. Modeling Analysis and Results*. Idaho Power will file the 2019 IRP in both the Idaho and Oregon jurisdictions.

Guideline 11: Reliability

Electric utilities should analyze reliability within the risk modeling of the actual portfolios being considered. Loss of load probability, expected planning reserve margin, and expected and worst-case unserved energy should be determined by year for top-performing portfolios. Natural gas utilities should analyze, on an integrated basis, gas supply, transportation, and storage, along with demand-side resources, to reliably meet peak, swing, and base-load system requirements. Electric and natural gas utility plans should demonstrate that the utility's chosen portfolio achieves its stated reliability, cost and risk objectives.

Idaho Power response:

The capacity planning margin and regulating reserves are discussed in Chapter 8. Portfolios. A loss of load expectation analysis and regional resource adequacy are discussed in *Chapter 9. Modeling Analysis.*

Guideline 12: Distributed Generation

Electric utilities should evaluate distributed generation technologies on par with other supply-side resources and should consider, and quantify where possible, the additional benefits of distributed generation.

Idaho Power response:

Distributed generation technologies were evaluated in *Chapter 4. Future Supply-Side Generation and Storage Resources* and in *Chapter 7. Planning Period Forecasts—Analysis of IRP Resources*.

Guideline 13: Resource Acquisition

a. An electric utility should, in its IRP:
   - Identify its proposed acquisition strategy for each resource in its action plan.

- Assess the advantages and disadvantages of owning a resource instead of purchasing power from another party.
- Identify any Benchmark Resources it plans to consider in competitive bidding.

Idaho Power response:

Idaho Power continues to evaluate resource ownership along with other supply options. Idaho Power conducts its resource acquisition and competitive bidding processes consistent with the rules established by Oregon in Order No. 18-324 issued on August 30, 2018 and codified in Oregon Administrative Rules 860-089-0010-0550.

Idaho Power identifies its proposed acquisition strategy in *Chapter 10. Preferred Portfolio and Action Plan—Action Plan (2019–2026).* Discussion of asset ownership versus market purchases is found in *Chapter 9. Modeling Analysis*.

b. Natural gas utilities should either describe in the IRP their bidding practices for gas supply and transportation, or provide a description of those practices following IRP acknowledgment.

Idaho Power response:

Not applicable.

COMPLIANCE WITH EV GUIDELINES

Guideline 1: Forecast the Demand for Flexible Capacity

Forecast the Demand for Flexible Capacity: The electric utilities shall forecast the balancing reserves needed at different time intervals (e.g. ramping needed within 5 minutes) to respond to variation in load and intermittent renewable generation over the 20-year planning period;

Idaho Power response:

A discussion of the 2019 IRP's analysis for the flexibility guideline is provided in *Chapter 8. Portfolios.*

Guideline 2: Forecast the Supply for Flexible Capacity

Forecast the Supply of Flexible Capacity: The electric utilities shall forecast the balancing reserves available at different time intervals (e.g. ramping available within 5 minutes) from existing generating resources over the 20-year planning period;

Idaho Power response:

A discussion of the planning margin and regulating reserves is found at *Chapter 8. Portfolios.*

Guideline 3: Evaluate Flexible Resources on a Consistent and Comparable Basis

In planning to fill any gap between the demand and supply of flexible capacity, the electric utilities shall evaluate all resource options, including the use of EVs, on a consistent and comparable basis.

Idaho Power response:

The adoption rate of EVs is discussed in Appendix A Sales and Load Forecast, *Company System Load—Electric Vehicles.*

State of Oregon Action Items Regarding Idaho Power's 2017 IRP

Action Item 1: EIM

Continue planning for western EIM participation beginning in April 2018.

Idaho Power response:

Idaho Power joined the western EIM in April 2018.

Action Item 2: Loss-of-load and solar contribution to peak

Investigate solar PV contribution to peak and loss-of-load probability analysis.

Idaho Power response:

Solar PV contribution to peak is discussed in *Chapter 4. Future Supply-Side Generation and Storage Resources – Renewable Resource – Solar*.

Loss-of-load probability analysis is discussed in *Chapter 9. Modeling Analysis – Loss of Load Expectation.*

Action Item 3: North Valmy Unit 1

Plan and coordinate with NV Energy Idaho Power's exit from coal-fired operations by year-end 2019. Assess import dependability from northern Nevada.

Idaho Power response:

Idaho Power's action plan continues to target 2019 as the exit date from North Valmy Unit 1. Idaho Power's exit from Valmy Unit 1 is discuss in *Chapter 3. Idaho Power Today – Existing Supply-Side Resource – Coal Facilities* and in *Chapter 7. Planning Period Forecasts – Generation Forecast for Existing Resources – Coal Resources – North Valmy*.

The assessment of import dependability from northern Nevada is discussed in *Chapter 6. Transmission Planning – Nevada without North Valmy.*

Action Item 4: Jim Bridger Units 1 and 2

Plan and negotiate with PacifiCorp and regulators to achieve earl retirement dates of year-end 2028 for Unit 2 and year-end 2032 for Unit 1.

Idaho Power response:

Idaho Power's 2019 IRP Action Plan is detailed in Chapter 10. Action Plan (2019-2026) and includes updated target dates for early exits during 2022 and 2026. Discussion of the modeling analysis to reach these target dates is at *Chapter 7. Planning Period Forecasts – Generation Forecast for Existing Resources-Coal Resources – Jim Bridger.* Discussion of risks related to these planning and negotiating actions is discussed in *Chapter 9. Modeling Analysis – Qualitative Risk Analysis.*

Action Item 5: B2H

Conduct ongoing permitting, planning studies, and regulatory filings.

Idaho Power response:

Idaho Power continues to include B2H in the preferred portfolio and action items include permitting, negotiation and execution of partner construction agreements, preliminary construction activities, acquisition of long-lead materials, and construction of B2H. Discussion and analysis of the completed planning studies and permitting and regulatory filing is found in *Chapter 6. Transmission Planning – Boardman to Hemingway*. Modeling design and analysis testing B2H in the 2019 IRP is found in *Chapter 8. Portfolios* and *Chapter 9. Modeling Analysis*.

Action Item 6: B2H

Conduct preliminary construction activities, acquire long-lead materials, and construct the B2H project.

Idaho Power response:

Idaho Power continues to include B2H in the preferred portfolio and action items include permitting, negotiation and execution of partner construction agreements, preliminary construction activities, acquisition of long-lead materials, and construction of B2H. Discussion and analysis of the completed planning studies and permitting and regulatory filing is found in *Chapter 6. Transmission Planning – Boardman to Hemingway*. Modeling design and analysis testing B2H in the 2019 IRP is found in *Chapter 8. Portfolios* and *Chapter 9. Modeling Analysis*.

Action Item 7: Boardman

Continue to coordinate with PGE to achieve cessation of coal-fired operations by year-end 2020 and the subsequent decommission and demolition of the unit.

Idaho Power response:

Idaho Power's action plan continues to target 2020 as the exit date from Boardman. Idaho Power's exit from Boardman is discussed in *Chapter 3. Idaho Power Today – Existing Supply-Side Resource – Coal Facilities* and in *Chapter 7. Planning Period Forecasts – Generation Forecast for Existing Resources – Coal Resources – Boardman*.

Action Item 8: Gateway West

Conduct ongoing permitting, planning studies, and regulatory filings.

Modifications: Idaho Power should provide additional information to the Commission on an ongoing basis on Energy Gateway's progress, Idaho Power's inclusion of it as a least-cost/least risk portfolio, the status of co-participants and Energy Gateway's role in the IRP.

Idaho Power response:

Discussion regarding Gateway West is found in *Chapter 6. Transmission Planning – Gateway West*.

Idaho Power files quarterly transmission updates regarding the Energy Gateway West transmission project and updates on the permitting or completion of the Boardman to Hemingway transmission line project with the OPUC in Docket RE 136. The transmission update for Q4 2018 was filed on January 15th, 2019 and the update for Q1 2019 was filed on April 30, 2019.

Action Item 9: Energy Efficiency

Continue the pursuit of cost-effective energy efficiency.

Modifications: In its 2019 IRP Idaho Power will report on future expanded energy efficiency opportunities and improvements to its avoided cost methodology.

Idaho Power response:

Idaho Power's energy efficiency opportunities and improvements to its avoided cost methodology are discussed in *Chapter 5. Demand-side Resources*.

Action Item 10: Carbon emission regulations

Continue stakeholder involvement in CAA Section 111(d) proceeding, or alternative regulations affecting carbon emissions.

Modifications: Idaho Power will provide a report as part of its 2019 IRP filing describing the risks to the company and its customers associated with climate change.

Idaho Power response:

Idaho Power continues to participate in carbon emission discussions and announced our Clean Energy Goal in March 2019. These efforts are discussed in *Chapter 2. Political, Regulatory, and Operational Issues*. Modeling of carbon regulation is discussed *in Chapter 8. Portfolios – Framework for Expansion Modeling – Carbon Price Forecasts*.

Action Item 11: North Valmy Unit 2

Plan and coordinate with NV Energy Idaho Power's exit from coal-fired operation by year-end 2025.

Idaho Power response:

Idaho Power's action plan continues to target 2025 as the exit date from North Valmy Unit 2. Idaho Power's exit from Valmy Unit 2 is discuss in *Chapter 3. Idaho Power Today – Existing Supply-Side Resource – Coal Facilities* and in *Chapter 7. Planning Period Forecasts – Generation Forecast for Existing Resources – Coal Resources – North Valmy*.

Other Item 1: 2019 IRP Preview

Idaho Power is required that five months prior to the filing of the 2019 IRP, Idaho Power file a report in this docket providing the following information:

- Comprehensive update of the B2H project.
- Information about the planned gas price forecast for the 2019 IRP, and any appropriate updates on the natural gas price forecast.
- A discussion of portfolio modeling options and preferences for the 2019 IRP.
- An update on Jim Bridger environmental control developments and options.
- Updates as requested by Staff.

Idaho Power response:

Idaho Power's filed the updated IRP Report with the OPUC on January 28, 2019.