Marginal Generation Cost – PG&E's Methodology

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Outline

- Defining terms
- PG&E’s Marginal Energy Cost Model (MEC)
  - Why PG&E uses Adjusted Net Load (ANL)
  - ANL Model fit for historical data
  - Enhancements for 2017 GRC: Ramping and curtailment
- Marginal Generation Capacity Costs (MGCC)
  - Annual MGCC, allocating MGCC to hours in the year
- Developing forecasts of MEC and MGCC
- Results for 2021 from PG&E’s 2015 RDW model
  - Weekday and weekend costs for MEC, MGCC, MGC

Definition of Marginal Generation Cost and its Components

Marginal Generation Cost = Marginal **Energy** Cost + Marginal Generation **Capacity** Cost

Marginal **Energy** Cost is cost of procuring energy to meet one additional MWh of load.

- Almost all from Day-Ahead CAISO market, some Real-Time.

MEC model uses public CAISO data to forecast Day Ahead prices.

Marginal Generation **Capacity** Cost is the cost of procuring capacity to meet one additional MW of peak load.

- Start with annual MGCC, then allocate to hours

PG&E's Marginal Energy Cost (Price) Model

What drives electricity prices?

Natural gas generators are almost always on the margin in California

- Heat rate based model: Forecast heat rate, then multiply by gas price

Hourly energy price is a function of the *residual load* that must be met by gas-fired generation after accounting for baseload and renewables

- Baseload (nuclear) and renewables (wind, solar, hydro) have limited dispatchability, essentially must run and are (almost) never on margin

So what is "residual load"? We call it "Adjusted Net Load" (ANL)

- CAISO backs out wind and solar, calls it net load
- PG&E's ANL subtracts not only wind and solar, but also hydro and nuclear

Prices are in PG&E's service territory; loads and generation over entire CAISO (so includes solar from south)

Why Adjusted Net Load?

Hydro and nuclear displace thermal generation just like wind and solar do.

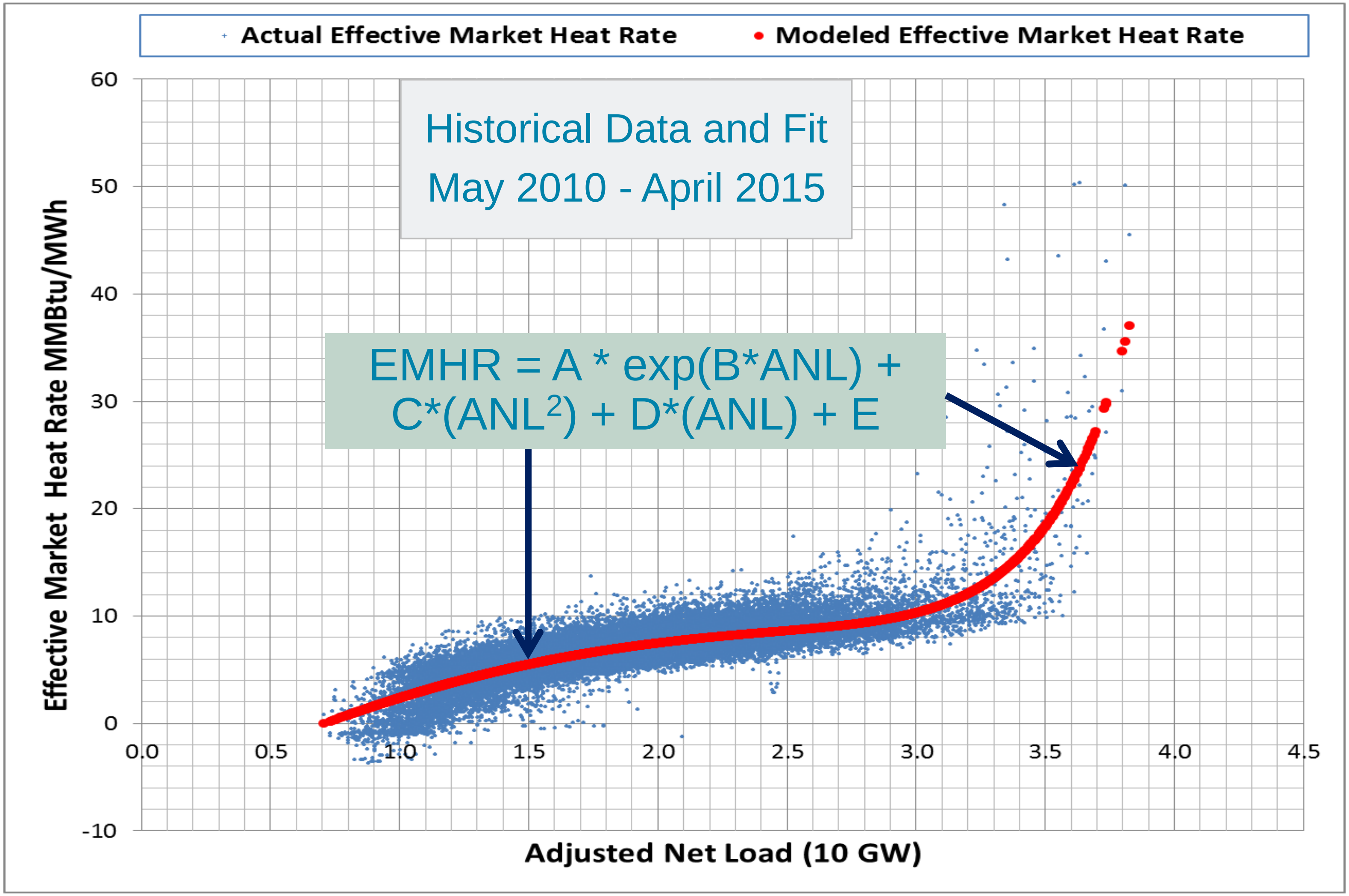
By not accounting for hydro and nuclear, an analysis based on net load may get timing of peak right but misses inter-annual variability.

Over three historical years, only ANL correlates well with average heat rate.

Year	2011	2013	2015
Average Heat Rate (MMBtu/MWh)	5.7	7.1	7.0
Gross Load (Avg GW)	26.3	26.7	26.5
Net Load (Avg GW)	25.4	24.6	23.4
Adjusted Net Load (Avg GW)	15.3	18.2	17.6

Bottom Line: Including hydro and nuclear yields better forecasts, especially in wet years like 2011.

PG&E's 2015 RDW Price Model Fits the Historical Data



Basic model: EMHR = Effective Market Heat Rate = F(ANL)

EMHR = (Energy price – VOM adder)/(Gas price + GHG adder)

2015 RDW Model Fit - Summer

- Heat maps of NP-15 Day-Ahead prices and Effective Market Heat Rates by year
- Very good agreement between modeled and actual prices/heat rates

Price in $/MWh

Summer average prices	2011 Modeled	2011 Actual	2013 Modeled	2013 Actual	2015 Modeled	2015 Actual
1	25	22	36	35	33	32
2	22	18	34	33	31	30
3	20	15	32	31	29	29
4	19	13	32	30	29	28
5	20	14	32	31	29	28
6	23	16	34	32	31	30
7	26	19	37	34	32	31
8	30	25	39	36	32	31
9	33	28	40	37	31	31
10	36	31	42	38	32	31
11	38	34	44	41	33	33
12	40	37	45	43	34	34
13	41	39	47	45	35	36
14	42	43	48	47	37	38
15	43	45	51	49	39	41
16	**44**	49	52	51	41	43
17	44	**51**	**53**	**55**	43	47
18	44	46	53	52	44	48
19	42	42	52	50	46	**50**
20	41	39	51	49	**46**	49
21	42	41	50	48	45	46
22	40	36	47	45	41	42
23	35	33	44	41	38	37
24	30	26	40	37	35	35

Effective Market Heat Rate

Summer average EMHR	2011 Modeled	2011 Actual	2013 Modeled	2013 Actual	2015 Modeled	2015 Actual
1	4.4	3.8	6.2	6.1	6.7	6.5
2	3.7	3.0	5.7	5.6	6.2	6.0
3	3.3	2.2	5.5	5.2	5.9	5.8
4	3.1	1.8	5.3	5.1	5.7	5.5
5	3.3	2.1	5.5	5.1	5.9	5.7
6	3.8	2.6	5.9	5.5	6.2	6.0
7	4.5	3.0	6.4	5.8	6.6	6.4
8	5.3	4.3	6.8	6.1	6.6	6.4
9	6.0	5.0	7.1	6.3	6.4	6.2
10	6.6	5.6	7.4	6.7	6.5	6.4
11	7.1	6.2	7.7	7.2	6.8	6.7
12	7.4	6.9	8.0	7.5	7.1	7.1
13	7.7	7.2	8.3	7.9	7.4	7.5
14	7.9	8.0	8.7	8.4	7.8	8.0
15	8.1	8.5	9.1	8.8	8.2	8.7
16	**8.3**	9.4	9.4	9.2	8.7	9.3
17	8.3	**9.7**	**9.6**	**9.9**	9.1	10.2
18	8.2	8.8	9.6	9.3	9.5	10.5
19	7.9	7.9	9.4	9.0	9.9	**10.8**
20	7.7	7.3	9.1	8.8	**10.0**	10.7
21	7.7	7.7	9.0	8.5	9.6	9.9
22	7.4	6.7	8.5	8.0	8.8	8.9
23	6.5	5.9	7.7	7.2	8.0	7.9
24	5.3	4.6	6.9	6.4	7.3	7.2

2015 RDW Model Fit - Winter

- Heat maps of NP-15 Day-Ahead prices and Effective Market Heat Rates by year
- Very good agreement between modeled and actual prices/heat rates

Price in $/MWh

Winter average prices	2010-11 Modeled	2010-11 Actual	2012-13 Modeled	2012-13 Actual	2014-15 Modeled	2014-15 Actual
1	24	23	31	32	32	31
2	22	19	29	31	30	29
3	20	16	28	29	29	28
4	20	15	28	29	29	28
5	21	18	29	29	30	29
6	24	24	32	32	32	33
7	28	29	35	36	35	37
8	31	34	37	38	36	38
9	32	33	38	38	34	35
10	34	34	38	38	33	33
11	34	35	38	39	32	32
12	35	35	39	39	32	32
13	34	33	38	38	32	32
14	34	32	38	38	33	32
15	34	31	39	38	33	32
16	34	31	39	39	35	34
17	34	32	40	41	37	39
18	36	37	42	45	40	46
19	37	40	43	**47**	42	**49**
20	37	**41**	**43**	47	**42**	48
21	**37**	40	43	45	42	47
22	35	35	41	41	40	42
23	32	32	38	38	38	38
24	27	26	34	34	34	34

Effective Market Heat Rate

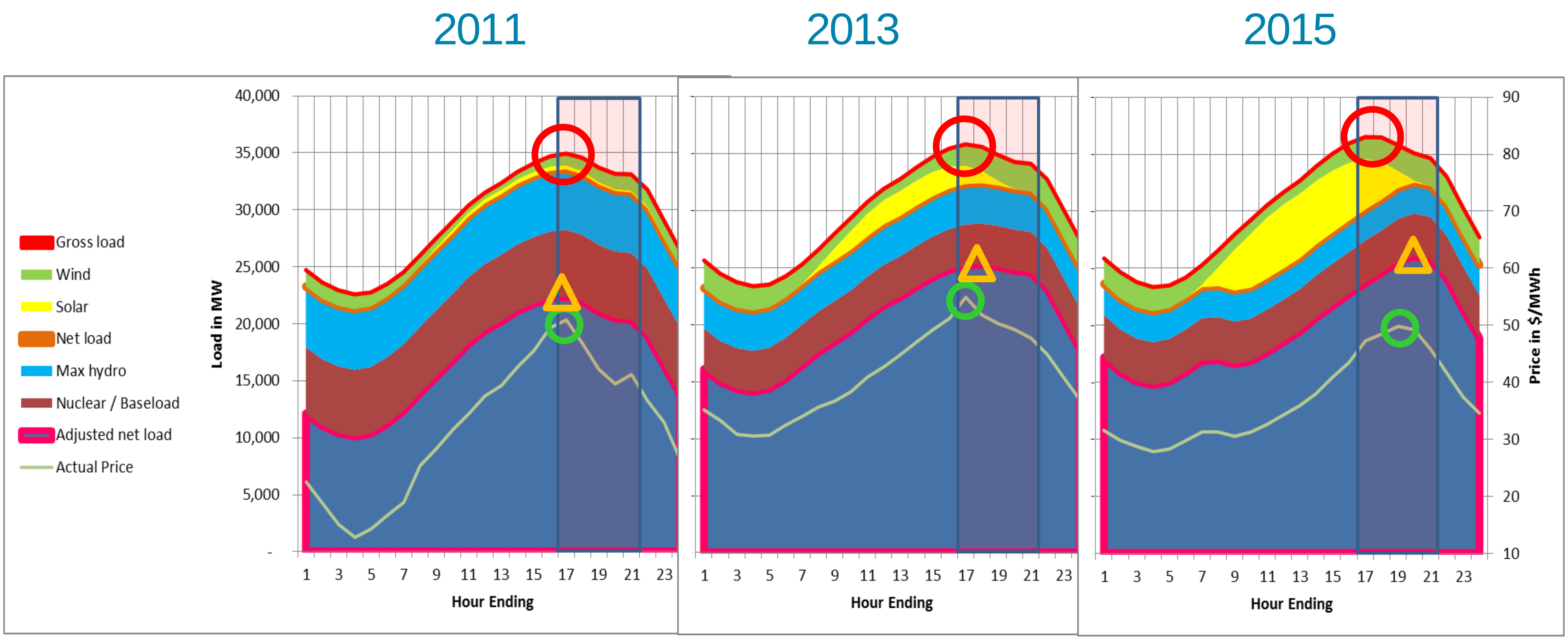
Winter average EMHR	2010-11 Modeled	2010-11 Actual	2012-13 Modeled	2012-13 Actual	2014-15 Modeled	2014-15 Actual
1	4.3	4.1	5.6	5.8	5.9	5.7
2	3.8	3.3	5.2	5.4	5.5	5.3
3	3.5	2.5	5.0	5.0	5.3	5.1
4	3.4	2.4	5.0	5.0	5.2	5.0
5	3.7	3.0	5.2	5.2	5.4	5.3
6	4.3	4.3	5.7	5.8	5.9	6.3
7	5.2	5.6	6.4	6.5	6.6	7.1
8	5.8	6.4	6.8	7.0	6.7	7.3
9	6.2	6.4	7.0	7.0	6.3	6.6
10	6.4	6.5	7.1	7.1	6.1	6.1
11	6.6	6.8	7.1	7.2	6.0	6.0
12	6.7	6.7	7.1	7.2	5.9	5.9
13	6.6	6.3	7.1	7.0	5.9	5.8
14	6.6	6.2	7.1	7.0	6.0	5.8
15	6.5	6.0	7.1	7.0	6.1	5.9
16	6.4	5.9	7.2	7.1	6.4	6.3
17	6.5	6.2	7.4	7.7	7.0	7.4
18	6.9	7.1	7.8	8.6	7.6	8.9
19	7.1	7.8	8.0	**9.0**	8.0	**9.6**
20	7.2	**8.1**	**8.1**	8.9	**8.1**	9.5
21	**7.3**	7.9	8.0	8.4	8.1	9.2
22	6.9	6.8	7.6	7.7	7.7	8.1
23	6.0	6.0	7.0	7.0	7.1	7.2
24	5.1	4.8	6.2	6.2	6.4	6.4

Why Model the Ramp?

Timing of peak in Gross Load has not shifted appreciably since 2011

Timing of peak in Net Load or ANL has shifted later, by 3-4 hours

Timing of peak in price/cost has also shifted, but not quite as far due to ramping effects



Summer (June-September) average loads and generation

Enhancements in 2017 GRC Model Ramping and Curtailment

Ramping can affect peak hours:

RDW model fits historical data well, but may underestimate intra-day price spreads and miss timing of peak due to ramp

- Turning on new generator during ramp boosts energy price

Increase heat rate when ramping up, decrease when ramping down

- Best fit based on ramp in ANL over 3-4 hrs

Improves fit, pulls modeled peak MEC a bit earlier

- Partially counteracts impact of rapid increase in solar on ANL

Curtailment can affect super off peak prices:

Model based on Day-Ahead market, historical prices do not reflect curtailment

- As of 2016, most curtailment (of wind/solar) has occurred in real time
- Enhanced model adjusts price downward in calibration when Real-Time price < Day-Ahead price
- Better (lower) estimate of marginal cost under conditions of curtailment
- Increases importance of considering super off peak TOU periods

PG&E's Marginal Generation Capacity Cost Model

Marginal Generation Capacity Costs

MGCC reflects changes in generation costs associated with meeting one additional MW of peak demand.

- Annual MGCC = all-in cost of generator minus revenue from spot market.

PG&E levelizes annual MGCC over six-year planning horizon.
Uses short-run cost of capacity for years prior to resource balance year and long-run cost of capacity after resource balance year.

For 2015 RDW, PG&E used levelized MGCC from 2014 GRC Phase II.

- Resource balance year = 2018 and MGCC = $57.09/kW-year.

For 2017 GRC Phase II, resource balance year > 2022, so annual MGCC is based on short-run cost of capacity.

- MGCC between $30-40/kW-year

Allocating Levelized MGCC to Hours

Many ways to apportion capacity cost

- Loss of Load Probability (LOLP) / Loss of Load Expectation (LOLE)
  - Traditional method of capacity allocation.
  - Can use E3's public RECAP model (driven by net load).
- Top 100 or 250 hours of net load or MECs
  - Net load or ANL
  - Energy prices (MECs)

All of these methods result in similar patterns of capacity costs, centered around late afternoon/evening in summer months

Developing forecasts of Adjusted Net Load, MEC and MGCC

Need forecasts of both MEC and MGCC

MEC forecast uses shapes from actual historical weather along with public forecasts of annual load and generation

- Forecast energy price scenarios into future assuming similar weather and increasing wind, solar penetration

Use 8760 pattern from LTPP Track 1A, then scale by annual GWh

- 8760 patterns: Load; wind; all solar; nuclear (planned outages); hydro

How about future curtailment?

- Assume renewables are curtailed at a “floor price” of -$15/MWh, even when ANL gets very low

2021 Weekday Costs (From 2015 RDW)

Marginal Energy Cost +
Marginal Capacity Cost =
Marginal Generation Cost

Weekdays - MEC in $/MWh as of 2021

Hour Ending	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
January	34	31	29	28	30	37	44	48	44	37	34	32	30	30	32	39	49	54	55	54	52	49	44	38
February	38	35	34	33	35	41	47	49	43	37	32	30	28	30	33	39	48	54	57	56	54	52	48	42
March	42	36	34	32	33	36	42	46	41	28	20	15	13	15	18	25	37	50	60	63	63	61	57	50
April	36	31	27	24	23	24	30	35	24	9	-2	-7	-10	-9	-4	4	16	32	48	50	54	56	52	46
May	35	29	26	24	24	26	30	29	25	17	13	12	13	14	20	27	35	43	51	51	52	53	51	45
June	46	42	38	35	34	35	39	33	30	25	25	26	27	28	34	40	48	55	61	64	62	62	60	54
July	55	51	48	45	44	45	47	45	42	39	41	43	44	47	51	57	66	80	115	136	103	96	78	63
August	54	50	47	45	44	44	48	50	46	42	41	42	43	46	51	56	60	66	82	82	74	74	66	60
September	47	44	41	39	38	39	43	47	41	33	31	30	30	32	37	43	49	56	63	62	63	62	57	52
October	46	42	40	38	37	39	42	47	45	34	29	30	30	32	36	41	47	55	57	58	60	58	55	51
November	38	35	32	31	33	38	43	44	37	28	24	23	22	26	31	41	51	57	58	57	56	53	49	43
December	44	41	38	38	40	46	54	56	48	39	35	31	30	32	37	50	63	69	70	69	67	64	59	50

Weekdays - MGCC in $/MWh as of 2021

Hour Ending	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
January																								
February																								
March																								
April																								
May																								
June																			5	23	7	1		
July															8	27	79	158	278	331	246	224	143	30
August																		40	194	193	122	113	21	
September																		1	45	28	34	20		
October																								
November																								
December																								

Weekdays - MGC in $/MWh as of 2021

Hour Ending	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
January	34	31	29	28	30	37	44	48	44	37	34	32	30	30	32	39	49	54	55	54	52	49	44	38
February	38	35	34	33	35	41	47	49	43	37	32	30	28	30	33	39	48	54	57	56	54	52	48	42
March	42	36	34	32	33	36	42	46	41	28	20	15	13	15	18	25	37	50	60	63	63	61	57	50
April	36	31	27	24	23	24	30	35	24	9	-2	-7	-10	-9	-4	4	16	32	48	50	54	56	52	46
May	35	29	26	24	24	26	30	29	25	17	13	12	13	14	20	27	35	43	51	51	52	53	51	45
June	46	42	38	35	34	35	39	33	30	25	25	26	27	28	34	40	48	55	66	87	69	64	60	54
July	55	51	48	45	44	45	47	45	42	39	41	43	44	47	59	85	145	237	393	467	349	320	221	93
August	54	50	47	45	44	44	48	50	46	42	41	42	43	46	51	56	60	107	276	275	196	187	87	60
September	47	44	41	39	38	39	43	47	41	33	31	30	30	32	37	43	49	57	108	89	97	82	57	52
October	46	42	40	38	37	39	42	47	45	34	29	30	30	32	36	41	47	55	57	58	60	58	55	51
November	38	35	32	31	33	38	43	44	37	28	24	23	22	26	31	41	51	57	58	57	56	53	49	43
December	44	41	38	38	40	46	54	56	48	39	35	31	30	32	37	50	63	69	70	69	67	64	59	50

2021 Weekend Costs (From 2015 RDW)

Marginal Energy Cost +
Marginal Capacity Cost =
Marginal Generation Cost

Weekends - MEC in $/MWh as of 2021

Hour Ending	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
January	41	37	34	33	35	39	44	46	38	23	16	12	10	11	17	32	56	68	71	69	67	62	56	47
February	35	32	30	30	31	34	36	37	28	21	17	13	10	11	17	27	42	51	54	54	52	50	45	40
March	31	26	25	22	22	22	24	25	18	6	0	-3	-4	-4	-2	2	12	25	37	41	42	41	37	33
April	29	25	22	19	18	18	20	20	4	-13	-20	-23	-24	-24	-24	-20	-6	13	31	34	38	40	37	31
May	44	37	32	29	28	29	31	20	6	-9	-17	-18	-17	-14	-8	3	18	36	52	55	56	59	56	48
June	34	30	28	25	24	25	25	15	8	1	-1	-1	-1	0	4	11	21	31	40	45	44	45	45	40
July	48	43	40	37	36	35	36	29	22	15	16	20	23	27	33	40	47	53	61	69	64	63	58	52
August	48	44	41	39	38	38	39	39	29	20	20	23	26	31	38	44	50	55	66	68	64	64	58	53
September	40	36	32	30	29	30	32	33	20	7	2	2	2	5	11	21	33	44	51	52	54	53	50	45
October	49	44	40	39	37	38	41	45	38	19	10	9	6	6	12	23	38	56	61	64	65	63	60	55
November	38	35	32	31	32	35	38	37	21	8	5	3	2	5	13	32	51	59	60	59	57	53	49	42
December	32	29	26	25	26	29	32	32	24	12	7	5	4	6	12	26	42	49	50	50	48	46	42	36

Weekends - MGCC in $/MWh as of 2021

Hour Ending	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
January																								
February																								
March																								
April																								
May																								
June																								
July																		9	73	132	91	81	38	
August																		10	88	103	70	73	20	
September																								
October																								
November																								
December																								

Weekends - MGC in $/MWh as of 2021

Hour Ending	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
January	41	37	34	33	35	39	44	46	38	23	16	12	10	11	17	32	56	68	71	69	67	62	56	47
February	35	32	30	30	31	34	36	37	28	21	17	13	10	11	17	27	42	51	54	54	52	50	45	40
March	31	26	25	22	22	22	24	25	18	6	0	-3	-4	-4	-2	2	12	25	37	41	42	41	37	33
April	29	25	22	19	18	18	20	20	4	-13	-20	-23	-24	-24	-24	-20	-6	13	31	34	38	40	37	31
May	44	37	32	29	28	29	31	20	6	-9	-17	-18	-17	-14	-8	3	18	36	52	55	56	59	56	48
June	34	30	28	25	24	25	25	15	8	1	-1	-1	-1	0	4	11	21	31	40	45	44	45	45	40
July	48	43	40	37	36	35	36	29	22	15	16	20	23	27	33	40	47	61	135	201	155	143	95	52
August	48	44	41	39	38	38	39	39	29	20	20	23	26	31	38	44	50	65	154	170	134	137	78	53
September	40	36	32	30	29	30	32	33	20	7	2	2	2	5	11	21	33	44	51	52	54	53	50	45
October	49	44	40	39	37	38	41	45	38	19	10	9	6	6	12	23	38	56	61	64	65	63	60	55
November	38	35	32	31	32	35	38	37	21	8	5	3	2	5	13	32	51	59	60	59	57	53	49	42
December	32	29	26	25	26	29	32	32	24	12	7	5	4	6	12	26	42	49	50	50	48	46	42	36

Thank You

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Appendix

Details on Hydro Modeling

Hydro generation reduces residual that must be met by thermal generation

- ➢Net load methods treat hydro just like thermal

But hydro also provides significant Ancillary Services which release capacity so thermal generators can run more efficiently

- ➢More bang for the buck: effect of hydro on prices is more than actual generation because of flexibility benefits

ANL model reduces net load based on capability of hydro to generate and provide ancillary services, which does not vary (much) by hour

- ➢Subtract 30-day moving average of daily maximum hydro

A really nice side benefit: don’t have to forecast how hourly or daily pattern of hydro generation will change with later peak