Resource Adequacy at PJM

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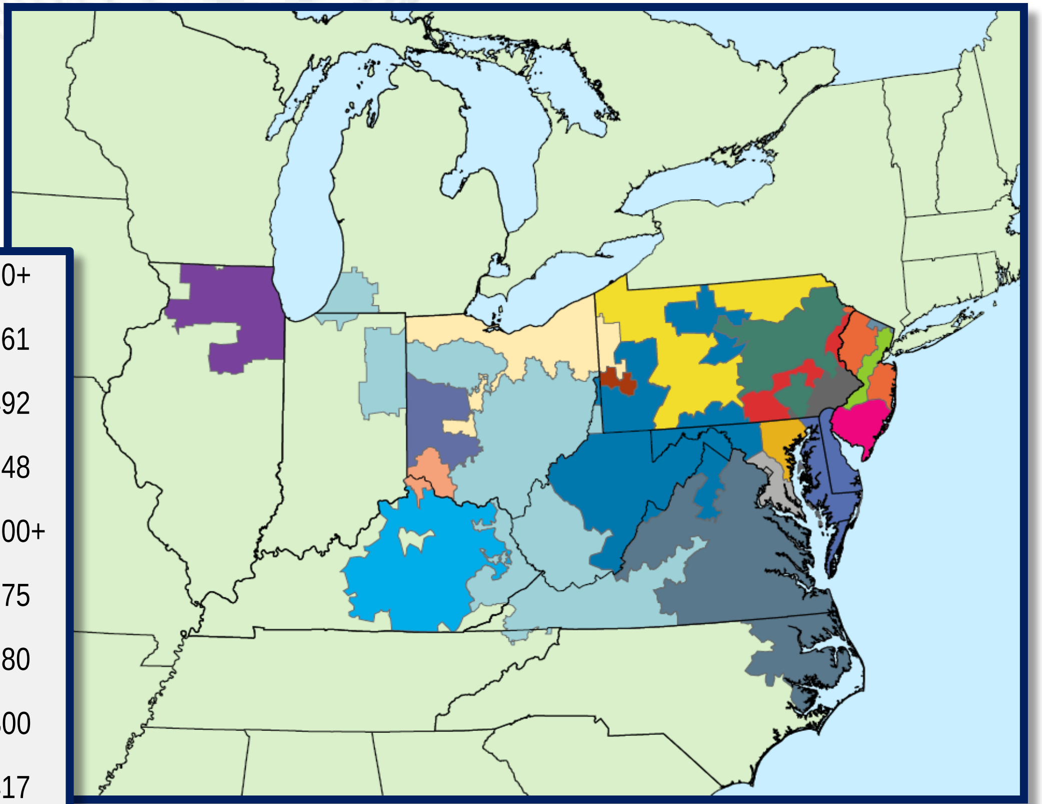
Resource Adequacy Planning

PJM RTO



Members	960+
Millions - people served	61
Peak Load (MW)	165,492
Generating Capacity (MW)	171,648
DR and EE (MW)	9,000+
Transmission Lines (Miles)	72,075
Energy (GW - 2015)	792,580
Generation Sources	~1,300
Area Served (Sq Miles)	243,417
States served	13 + DC

~21% of U.S. GDP

Motivation

- Sources of uncertainty in resource adequacy planning
  - Load
  - Resource Performance
    - Generation
    - Demand Response
  - Transmission
- Main concern for adequacy planners

  If X = Sum of Available Resources at time t

  Y = Load at time t

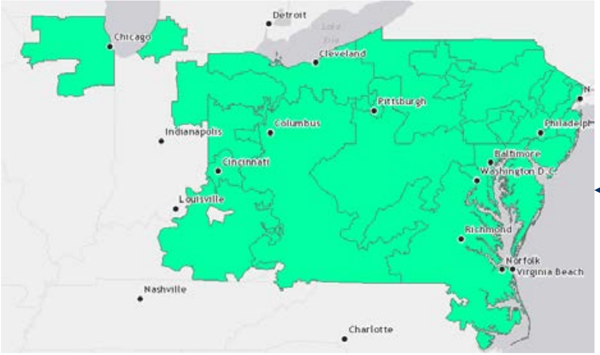
  then a **Loss of Load Event** (LOLE) takes place when X < Y
- Ensure availability of adequate capacity resources
  - Capacity market (PJM's Reliability Pricing Model)

Probabilistic Adequacy Studies at PJM

- Reserve Requirement (aka Installed Reserve Margin Study)
- Capacity Emergency Transfer Objective (CETO)
- Demand Response (DR) Caps

Reserve Requirement Study (RRS)

- Objective
  - Compute Installed Reserve Margin (IRM)
  - IRM then is used to construct a downward sloping demand curve in Reliability Pricing Model (RPM)
- Approach



PJM

⟷ Capacity Benefit Margin (CBM)

MISO
ISO-NE
NYISO
TVA
VACAR

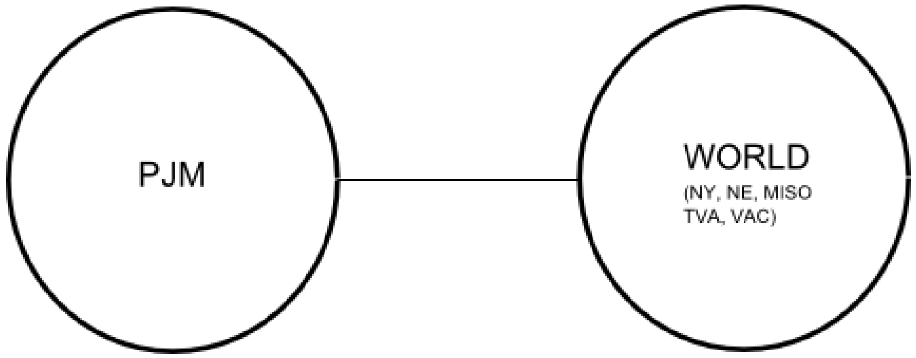
World

IRM/FPR Basics - Software

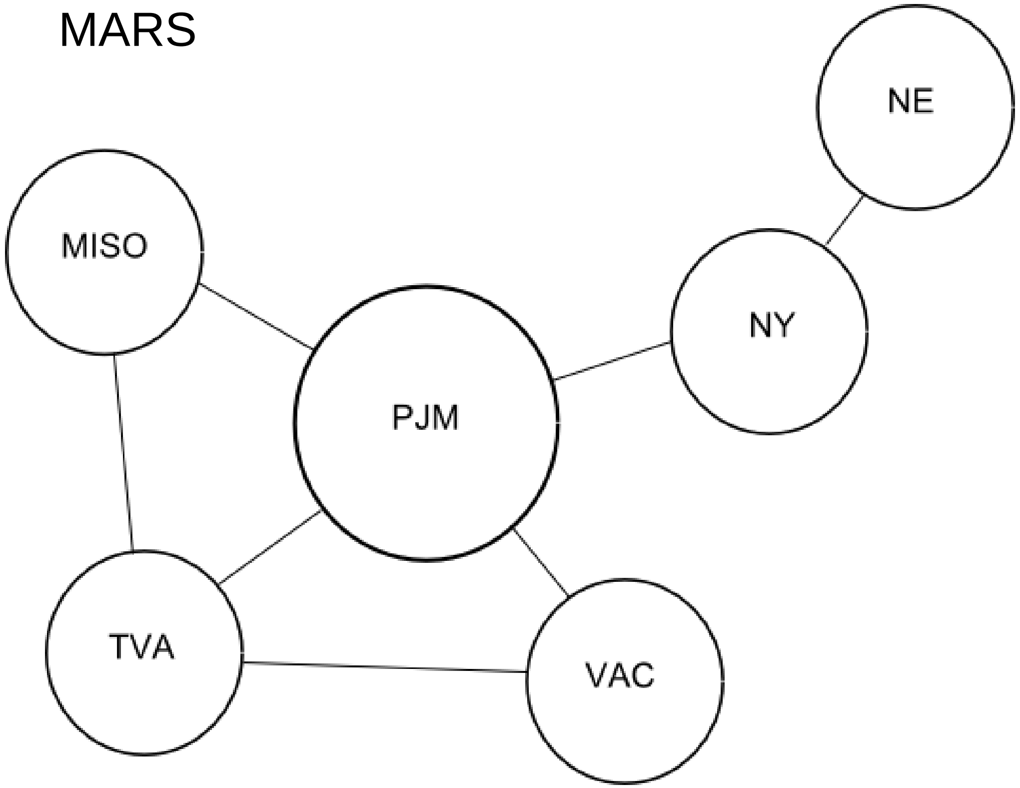
PRISM	MARS
Topology	***Topology***
two-area	multi-area
Load Model	***Load Model***
52 normal distributions; one per week	hourly load shape for entire year (per-unitized hourly loads)
per-unitized monthly peaks	12 distributions (may or may not be normal); one per month
forecast error factor	per-unitized monthly peaks
daily lole computation	hourly lole computation
Capacity Model	***Capacity Model***
outage distribution developed via convolution	outage distribution developed via monte carlo simulation
units' forced outage rates	units' forced outage rates
units' planned outages requirement (in weeks)	units' planned outages requirement (in weeks)
units' icap	units' icap
	units' transition states
	allows for more granular input data (wind/solar hourly shapes, partial outages, etc)
Solution Method	***Solution Method***
daily lole computation	hourly lole computation
automated	trial-and-error

IRM/FPR Basics – Software – Topology

PRISM



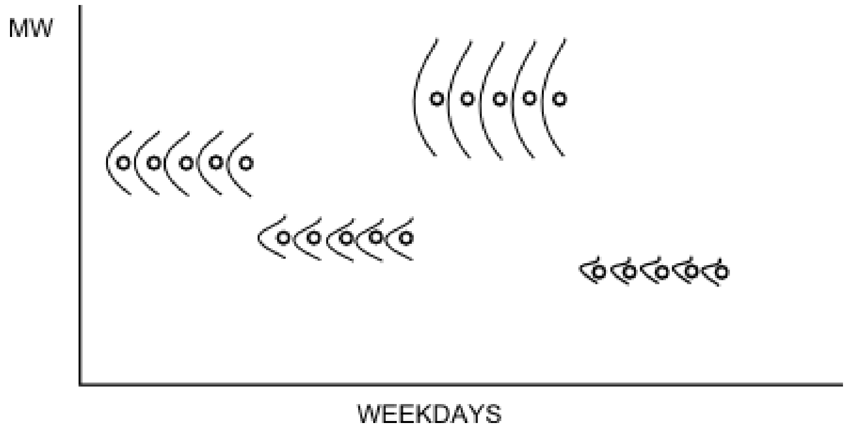
MARS



IRM/FPR Basics – Software – Load Model

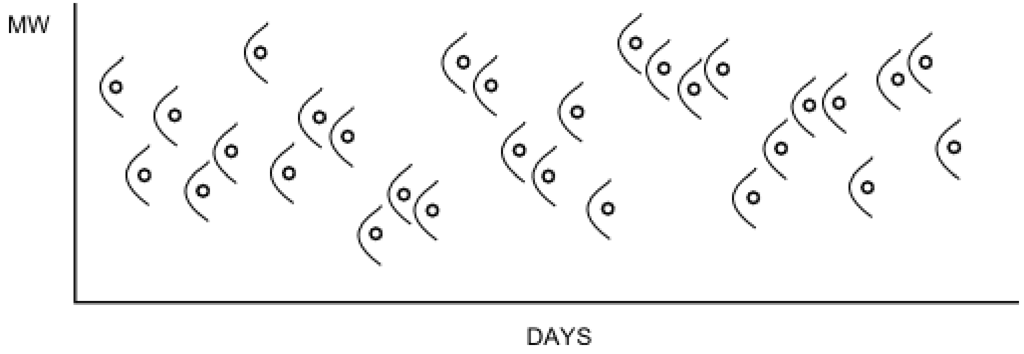
PRISM

Daily peaks with Weekly Uncertainty for a given month



MARS

Daily peaks with Monthly Uncertainty for a given month
(rest of hours not shown but their uncertainty is identical)



IRM/FPR Basics – Software – Capacity Model

PRISM

For each weekday, PRISM develops a probabilistic distribution of outages by:

- Assuming that each unit has a probability equal to its forced outage rate of being offline and a probability of one minus its forced outage rate of being online

- The online/offline probabilities of units not on planned outages in the weekday considered are convoluted one by one to develop a probabilistic distribution of outages

PRISM uses the convolution method to develop the capacity model

MARS

For each hour, MARS develops a probabilistic distribution of outages by:

- Combining the forced outages and transition states of a unit to develop distributions of length of online/offline periods

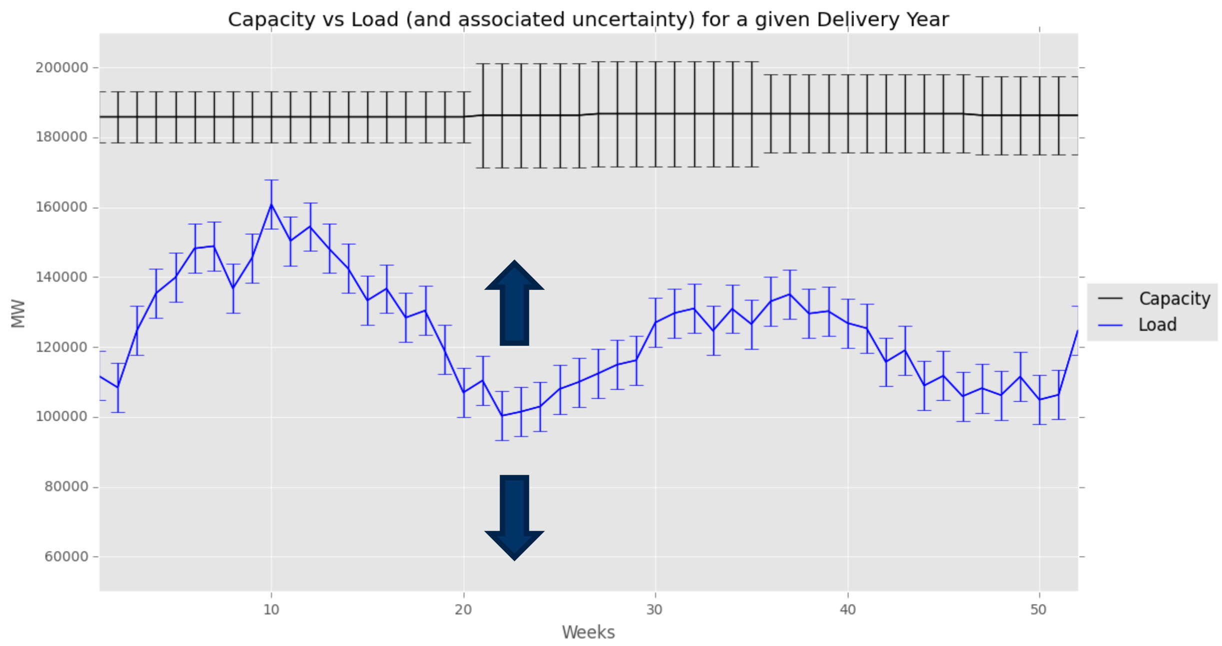
- Drawing random numbers for each unit that are then used in the above distributions to determine length of online/offline periods in current replication

- Repeat the procedure above “n” times (“n” replications)

- Sum the MWs of the units offline in each replication. Each replication is assumed to have equal probability.

MARS uses Monte Carlo sampling to develop the capacity model

IRM/FPR Basics – Solution Techniques



Starting point: forecasted 50/50 load and forecasted installed capacity

It is highly likely that the starting point will result in an LOLE above/below the 1 day in 10 years criterion

Thus, either the forecasted installed capacity or the forecasted 50/50 remains fixed while the other variable is shifted until meeting the criterion.

PJM chooses to fix the installed capacity and shift the 50/50 load.

- In summary, the RRS has 3 main inputs:
  - PJM's Load Model
  - PJM's Capacity Model (Outages)
  - World (Load Model and Capacity Model)

Input #1: Load Model – PJM Load Forecast

- As mentioned earlier, there is uncertainty in the forecasted load
- In fact, the PJM Load Forecast produces the following,

Weather Scenario	CP1	CP2	CP3	CP4	CP5	CP6	CP7	CP8	CP9	CP10
257 Additional Scenarios with CP1 value greater than CP1 value at Scenario C1983										
C1983	163596	160540	160453	160318	159349	159155	156290	156019	154408	153574
E2002	163573	163060	161448	161376	160637	158294	158199	157616	157112	156261
J1981	163436	163339	157416	155687	153274	151047	150504	150054	149264	147379
A1994	163192	162646	160241	158207	157002	153207	150821	150085	149942	148557
D1993	163074	161996	161817	159583	159354	158821	155885	155831	152421	151976
G1994	162980	162610	161455	160351	157150	155240	151272	150532	150019	149143
H1994	162972	162600	161481	160379	157135	155224	151269	150597	150577	150208
D2010	162904	162760	162259	161645	159410	158621	157642	156469	155836	155519
H1977	162665	161650	159774	159250	157884	155762	154621	152005	151599	151382
G1977	**162618**	**161609**	**159737**	**159212**	**157844**	**155726**	**154593**	**151980**	**151531**	**151306**
I1989	162456	159807	159124	155210	154597	153615	152966	150881	150774	148911
I1986	162372	160432	157358	151683	150770	149439	148560	147918	147205	144748
F1986	162341	160404	151643	151117	150725	149384	148504	147875	147153	144707
H1986	162227	161860	157570	153617	150566	149302	149135	144776	144514	143956
G1986	162200	161820	157541	153577	150515	149247	149087	144739	143979	143907
J1986	162160	160579	157316	156936	150899	149224	148698	147845	147835	145387
L1990	162079	157592	150781	149059	147649	145235	144572	143426	141423	139775
C1990	162049	157430	151334	150731	149885	149023	147601	147492	145162	144523
I1998	162001	160091	155635	154953	152744	150403	149567	149130	148109	147133
257 Additional Scenarios with CP1 value less than CP1 value at Scenario I1998										

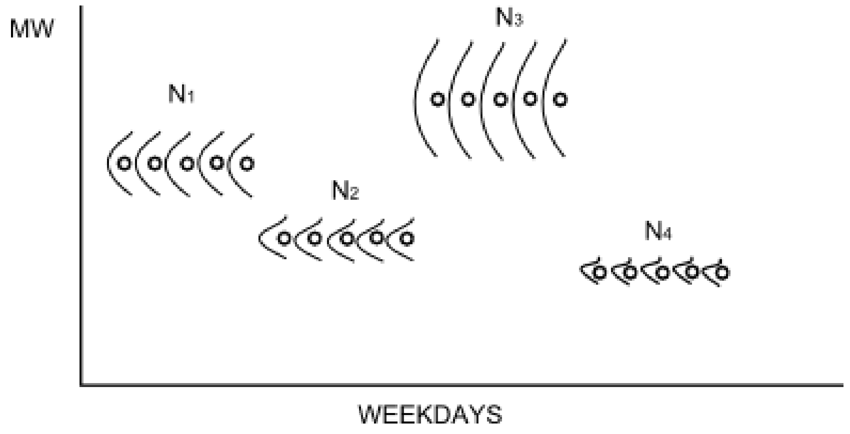
For each weather scenario, PJM determines the highest forecasted load and places the value in CP1, the second highest in CP2, and so on. Thus, the PJM Load Forecast uses a magnitude order approach (as opposed to a calendar order)

The forecasted 50/50 corresponds to the median of the CP1 values. However, there are other values, larger and smaller than the median, which altogether constitute the CP1 distribution (the 90/10 load published in the Load Forecast is derived from this distribution)

Input #1: Load Model – PJM Load Forecast

- PJM Load Forecast produces an annual peak distribution (annual peak uncertainty)
- Should this uncertainty then be used in the RRS?
  - It could be used; however
  - the PJM Load Forecast produces daily peaks whose uncertainty is modeled via discrete distributions.
  - PRISM, on the other hand, allows for uncertainty to be input via normal distributions
- Thus, we need to find a PRISM Load Model that matches the PJM Load Forecast uncertainty

- PRISM can accommodate a per-unitized daily peak load model with uncertainty introduced on a weekly basis via normal distributions (N)



- For an entire delivery year, this means inputting 52 normal distributions (N1, N2,…, N52)

Input #1: Load Model – PRISM Load Models

- For each of the Normal Distributions, the Most Probable Peak (MPP) of each week can be computed as

MPP = mean + 1.16295 x standard deviation

where 1.16295 is an empirical value associated with the expected value of the maximum of a set of 5 samples drawn from a normal distribution.

Since there are 5 weekdays in a week, the MPP formula above is used to estimate the magnitude of the highest daily peak in a week.

Input #1: Load Model – PRISM Load Models

- Currently, the Normal Distributions are obtained by looking at historical daily peak loads within a range of years
- Two options: calendar-order vs magnitude-order
- Example: PRISM Load Model for RTO from a 3 year period for 4 weeks in July

Year 1			
Week	Mean	StDev	MPP
1	121186	7579	130000
2	111958	7060	120169
3	118321	4533	123592
4	109338	7547	118115

Year 2			
Week	Mean	StDev	MPP
1	107812	4555	113110
2	108059	9544	119158
3	126411	4806	132000
4	115105	3503	119178

Year 3			
Week	Mean	StDev	MPP
1	119536	4040	124234
2	106504	2066	108907
3	113853	14744	131000
4	114156	2998	117642

Input #1: Load Model – PRISM Load Models

- Calendar-Order

	Year 1		Year 2		Year 3		Final (Mixture)		Per-Unitized			
Week	Mean	StDev	Mean	StDev	Mean	StDev	Mean	StDev	Mean	StDev	MPP	Per-U MPP
1	121186	7579	107812	4555	119536	4040	116178	5613	0.9720	0.0483	1.0266	0.9412
2	111958	7060	108059	9544	106504	2066	108840	6957	0.9106	0.0639	0.9783	0.8969
3	118321	4533	126411	4806	113853	14744	119528	9328	1.0000	0.0780	1.0908	1.0000
4	109338	7547	115105	3503	114156	2998	112866	5106	0.9443	0.0452	0.9939	0.9112

Straightforward approach

No re-ordering of weeks is needed to compute Means and StDevs of the Final Distributions

However, final distribution indicates MPP occurs in Week 3, while it can be seen that the MPP of Year 1 occurred in Week 1

Input #1: Load Model – PRISM Load Models

- Magnitude-Order
  - First Step: Compute Average MPPs

Week	Year 1 MPP	Year 2 MPP	Year 3 MPP	Avg MPP	Rank
1	130000	113110	124234	122448	2
2	120169	119158	108907	116078	4
3	123592	132000	131000	128864	1
4	118115	119178	117642	118312	3

  - To compute the Means and StDevs of the Final Distributions, we re-order the weeks so that the week with the highest MPP on each year is moved to week 3, the week with the second highest MPP is moved to week 1, etc

Input #1: Load Model – PRISM Load Models

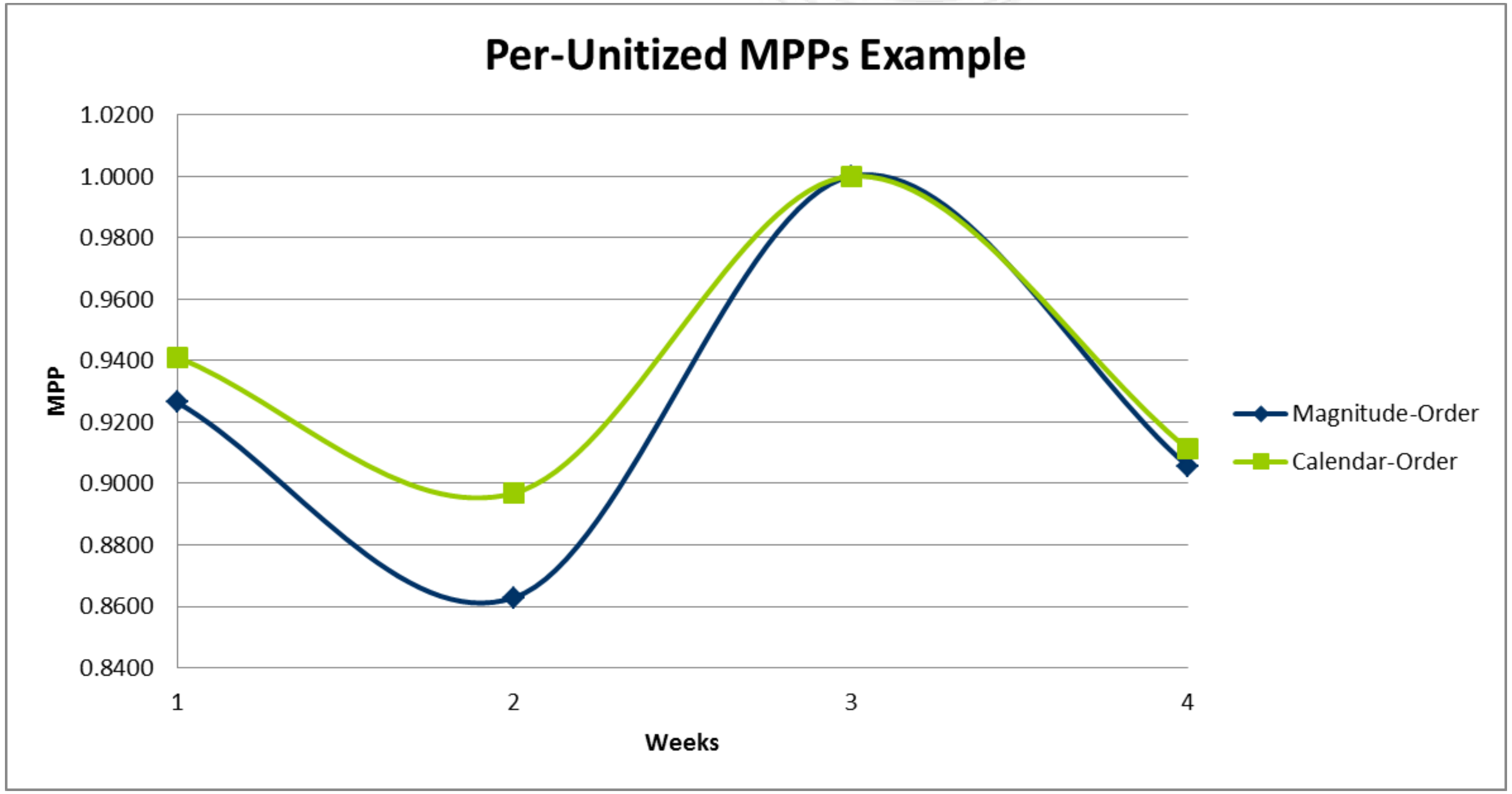
- Magnitude-Order

	Year 1		Year 2		Year 3		Final (Mixture)		Per-Unitized			
Week	Mean	StDev	Mean	StDev	Mean	StDev	Mean	StDev	Mean	StDev	MPP	Per-U MPP
1	118321	4533	115105	3503	119536	4040	117654	4047	0.9765	0.0344	1.0156	0.9265
2	109338	7547	107812	4555	106504	2066	107885	5227	0.8954	0.0485	0.9459	0.8629
3	121186	7579	126411	4806	113853	14744	120483	9965	1.0000	0.0827	1.0962	1.0000
4	111958	7060	108059	9544	114156	2998	111391	7069	0.9245	0.0635	0.9928	0.9057

Weeks on the individual years were re-ordered based on the value of the weekly Average MPP

Final distribution indicates MPP occurs in Week 3. This is also true for each of the individual years.

Input #1: Load Model – PRISM Load Models



Calendar-Order
load models
tend to result in flatter
load shapes

Input #1: Load Model – PRISM Load Models

- The 52 normal distributions are used in PRISM as follows,
  - 21 Load Scenarios are considered

x	Probability
-4.2	0.000033
-3.78	0.000145
-3.36	0.000638
-2.94	0.002351
-2.52	0.007273
-2.1	0.01894
-1.68	0.0414
-1.26	0.07608
-0.84	0.11749
-0.42	0.15248
0	0.16634
0.42	0.15248
0.84	0.11749
1.26	0.07608
1.68	0.0414
2.1	0.01894
2.52	0.007273
2.94	0.002351
3.36	0.000638
3.78	0.000145
4.2	0.000033

The weekly loads examined by scenario are given by the equation:

Load = weekly mean + x* weekly stdev

with x as indicated in the table on the left. The corresponding load scenario probabilities are also in the table.

Input #1: Load Model – PRISM Load Models

- In the Example with the 4 weeks in July using a Magnitude-Order LM.

Week	Mean	StDev	MPP
1	0.9765	0.0344	1.0156
2	0.8954	0.0485	0.9459
3	1.0000	0.0827	1.0962
4	0.9245	0.0635	0.9928

- If the Solved Load is 155,000,

				SCEN1	SCEN2	SCEN3	SCEN4	SCEN5	SCEN6	SCEN7	SCEN8	SCEN9	SCEN10	SCEN11	SCEN12	...
				4.2	3.78	3.36	2.94	2.52	2.1	1.68	1.26	0.84	0.42	0	-0.42	...
Week	Mean	StDev	MPP	3.3E-05	0.00015	0.00064	0.00235	0.00727	0.01894	0.0414	0.07608	0.11749	0.15248	0.16634	0.15248	...
1	138078	4750	143602	158027	156032	154037	152042	150047	148053	146058	144063	142068	140073	138078	136083	...
2	126613	6135	133748	152378	149802	147225	144649	142072	139496	136919	134343	131766	129190	126613	124037	...
3	141399	11695	155000	190519	185607	180695	175783	170871	165959	161047	156135	151223	146311	141399	136487	...
4	130728	8296	140376	165572	162088	158603	155119	151635	148150	144666	141181	137697	134213	130728	127244	...

It can be seen that the peak in every scenario occurs in week 3. This is consistent with the underlying data used to construct the load model (since the load model was constructed by magnitude-ordering the MPPs)

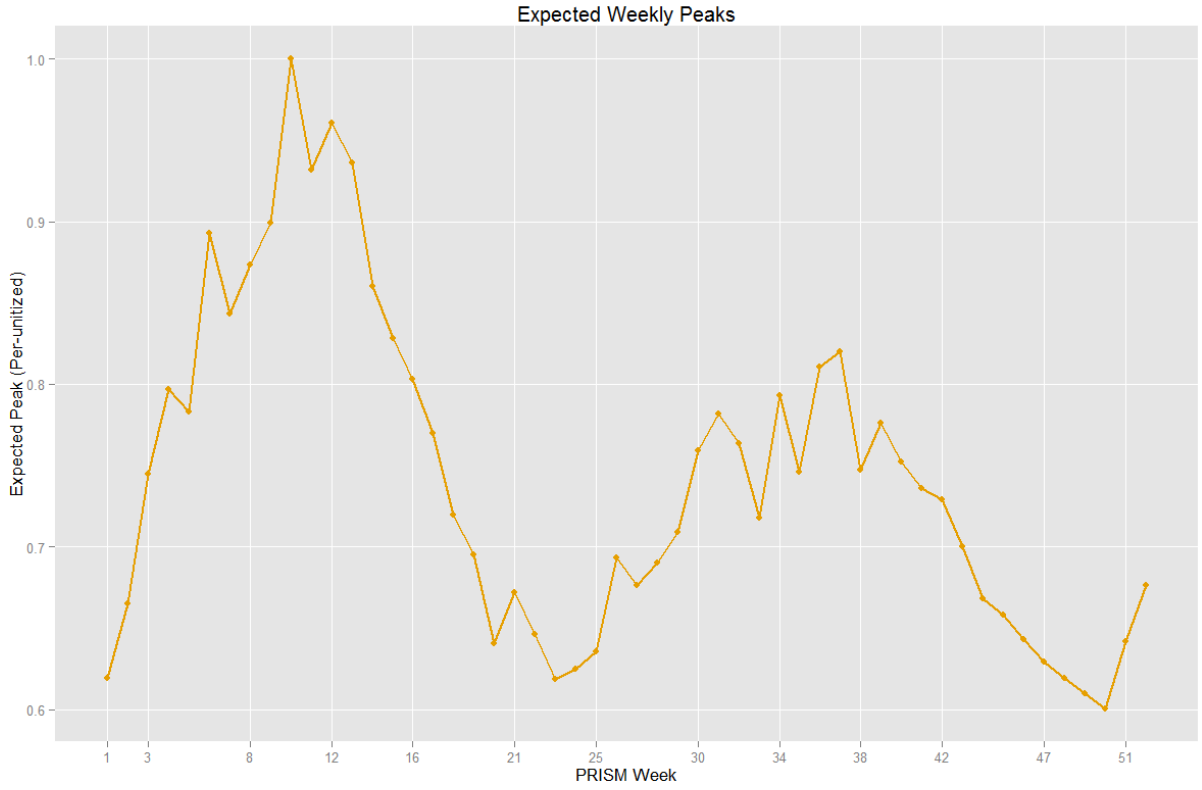
Input #1: Load Model – PRISM Load Models

- In addition, PRISM allows for the inclusion of
  - Forecasted monthly shape: relationship between monthly peaks in per unitized terms (from PJM’s Load Forecast)
  - Forecast error factor (FEF): accounts for additional load uncertainty via increasing standard deviation in weekly normal distributions (currently at 0.01)

Input #1: Load Model – PRISM Load Models

Initial PRISM Load Model

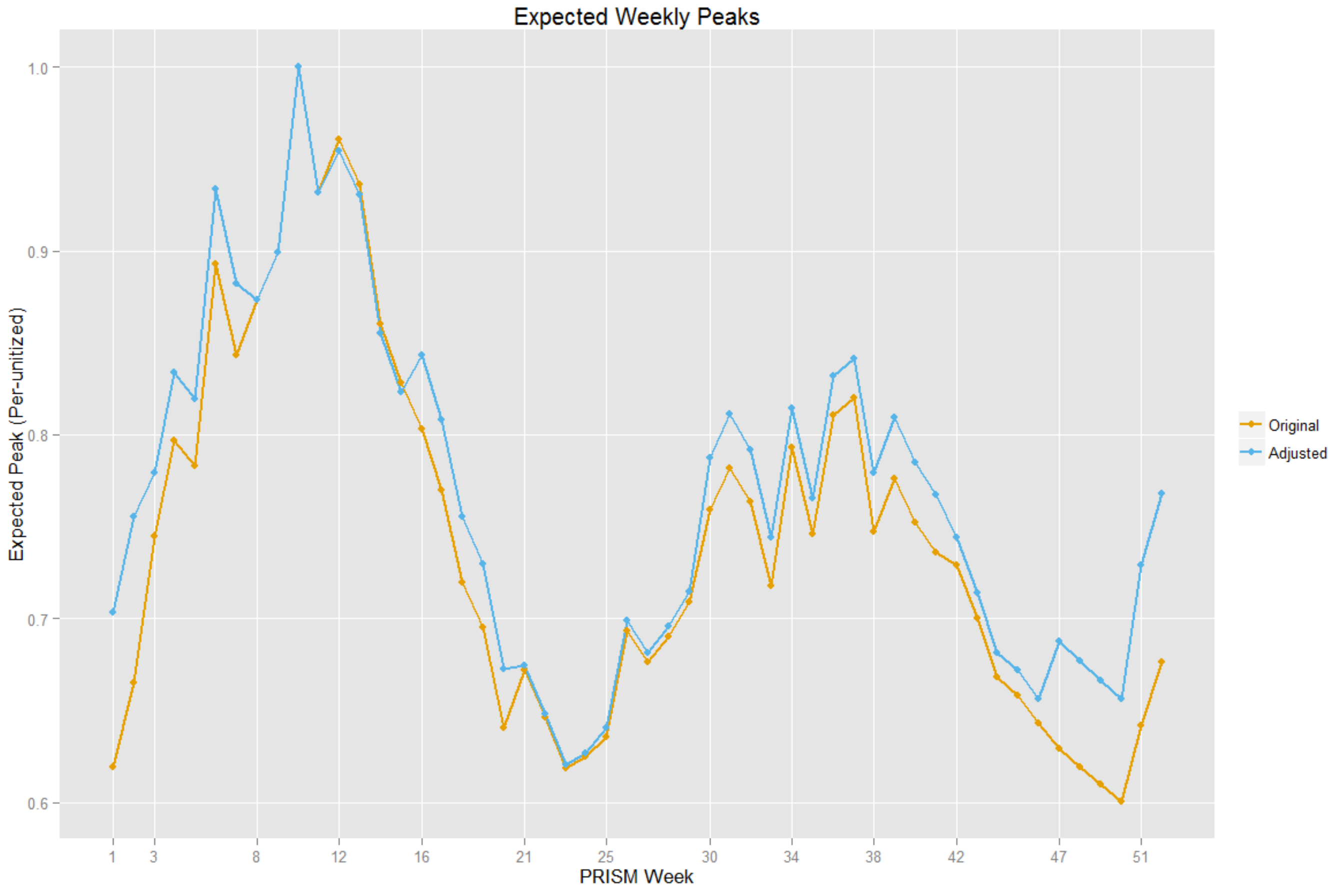
ARC Week	Mean	StDev	Month	Expected Peak
1	0.653806	0.029374	May	0.619268
2	0.689158	0.046401	May	0.665251
3	0.76381	0.055386	June	0.744623
4	0.8093	0.064312	June	0.796665
5	0.803414	0.055205	June	0.783077
6	0.896342	0.075034	June	0.892585
7	0.877478	0.042145	June	0.843061
8	0.907979	0.043372	July	0.873553
9	0.917895	0.060105	July	0.899452
10	1	0.078969	July	1
11	0.939737	0.070929	July	0.931689
12	0.976441	0.063557	August	0.960411
13	0.941334	0.07372	August	0.936071
14	0.880201	0.05786	August	0.86041
15	0.831368	0.075286	August	0.828106
16	0.818871	0.061225	September	0.803394
17	0.765412	0.084216	September	0.769689
18	0.735947	0.058343	September	0.719778
19	0.717306	0.0499	September	0.695096
20	0.666088	0.042799	September	0.640427
21	0.689096	0.055831	October	0.672112
22	0.67393	0.040311	October	0.64618
23	0.657351	0.023184	October	0.618292
24	0.659539	0.02966	October	0.6249
25	0.66919	0.03173	November	0.635522
26	0.696	0.07558	November	0.693484
27	0.70095	0.04589	November	0.676255
28	0.71963	0.04051	November	0.690145
29	0.74095	0.03876	November	0.709213
30	0.78566	0.04732	December	0.759176
31	0.80762	0.04913	December	0.781953
32	0.775	0.06492	December	0.763404
33	0.7493	0.03916	December	0.717534
34	0.81002	0.05933	January	0.793068
35	0.75824	0.06348	January	0.745735
36	0.81943	0.06886	January	0.810616
37	0.82817	0.0696	January	0.819907
38	0.76145	0.06156	February	0.747333
39	0.7936	0.05848	February	0.776277
40	0.778	0.04822	February	0.752519
41	0.76479	0.04326	February	0.7357
42	0.75175	0.0507	March	0.729117
43	0.72764	0.04346	March	0.700124
44	0.6999	0.03605	March	0.667905
45	0.68427	0.04344	March	0.658372
46	0.67344	0.03684	March	0.643215
47	0.65681	0.03972	April	0.629352
48	0.65115	0.03294	April	0.619229
49	0.64267	0.03083	April	0.60972
50	0.63765	0.02424	April	0.600474
51	0.66777	0.04235	May	0.641725
52	0.67763	0.07675	May	0.67603



Input #1: Load Model – PRISM Load Models

Initial PRISM Load Model adjusted for the Forecasted Monthly Shape

Month	Per-Unitized Peak
Jun	0.933919
Jul	1.000000
Aug	0.954611
Sep	0.843418
Oct	0.674150
Nov	0.714804
Dec	0.811220
Jan	0.841647
Feb	0.809492
Mar	0.743823
Apr	0.687919
May	0.767775



Input #1: Load Model – PRISM Load Models

Impact of the FEF on the load model

ARC Week	Mean	StDev	Month	Expected Peak	New StDev
34	0.81002	0.05933	January	0.793068	0.06016
35	0.75824	0.06348	January	0.745735	0.06427
36	0.81943	0.06886	January	0.810616	0.06959
37	0.82817	0.0696	January	0.819907	0.07032
38	0.76145	0.06156	February	0.747333	0.06237
39	0.7936	0.05848	February	0.776277	0.05933
40	0.778	0.04822	February	0.752519	0.04925
41	0.76479	0.04326	February	0.7357	0.04440
42	0.75175	0.0507	March	0.729117	0.05168
43	0.72764	0.04346	March	0.700124	0.04460
44	0.6999	0.03605	March	0.667905	0.03741
45	0.68427	0.04344	March	0.658372	0.04457
46	0.67344	0.03684	March	0.643215	0.03817

FEF increases the Standard Deviation of each week.
FEF does not increase the expected peaks, only the uncertainty around them

- Capacity Model refers to
  - Developing an Available Capacity probabilistic distribution (or conversely, an Outages probabilistic distribution)
  - Developing a deterministic schedule of Planned Outages
  - Modeling ambient derations
- Inputs to develop the Available Capacity distribution: Units' Forced Outage Rates (EEFORd), Units' Installed Capacity Values (in MW)
  - Installed Capacity Values are based on 50/50 weather
- Inputs to develop the Planned Outages schedule: Units' Equivalent Planned Outage Factors (EPOF, in weeks)

Input #2: Capacity Model

- Units included in the Capacity Model
  - Internal units eligible to bid in RPM (not necessarily committed for a future year)
  - External units that have long term contracts (for entirety of study period)
  - Future units that are currently in the interconnection queue. Their ICAP value gets adjusted as follows,

    Adjusted ICAP = ICAP x Commercial Probability
  - No DR or EE are included.

- EEFORd: Effective Equivalent Forced Outage Rate (Demand)

EEFORd = EFORd + (0.25 x EMOF)

EFORd: portion of time that a generating unit is in demand, but is unavailable due to a forced outage. It also includes forced outage derations.

EMOF: Equivalent Maintenance Outage Factor. One-quarter of this factor is added to the EFORd to account for unplanned maintenance outages that occur in summer.

- EPOF: Equivalent Planned Outage Factors. It is measured in weeks/year and includes planned derations.

Input #2: Capacity Model

- Source of data to compute these indices for each unit
  - eGADS: PJM’s web-based Generator Availability Data System based on NERC GADS data reporting requirements
  - Indices are reviewed by Generator Owner prior to every RRS
- Historical period used to compute these indices for each unit
  - Most recent 5 year period
  - This period is believed to provide enough hours of data and to be an acceptable representation of future performance of units.
  - For future units, PJM class averages are used
  - For units without 60 months of data, actual data and class average data are combined to derive the indices.

Input #2: Capacity Model

- Class Averages

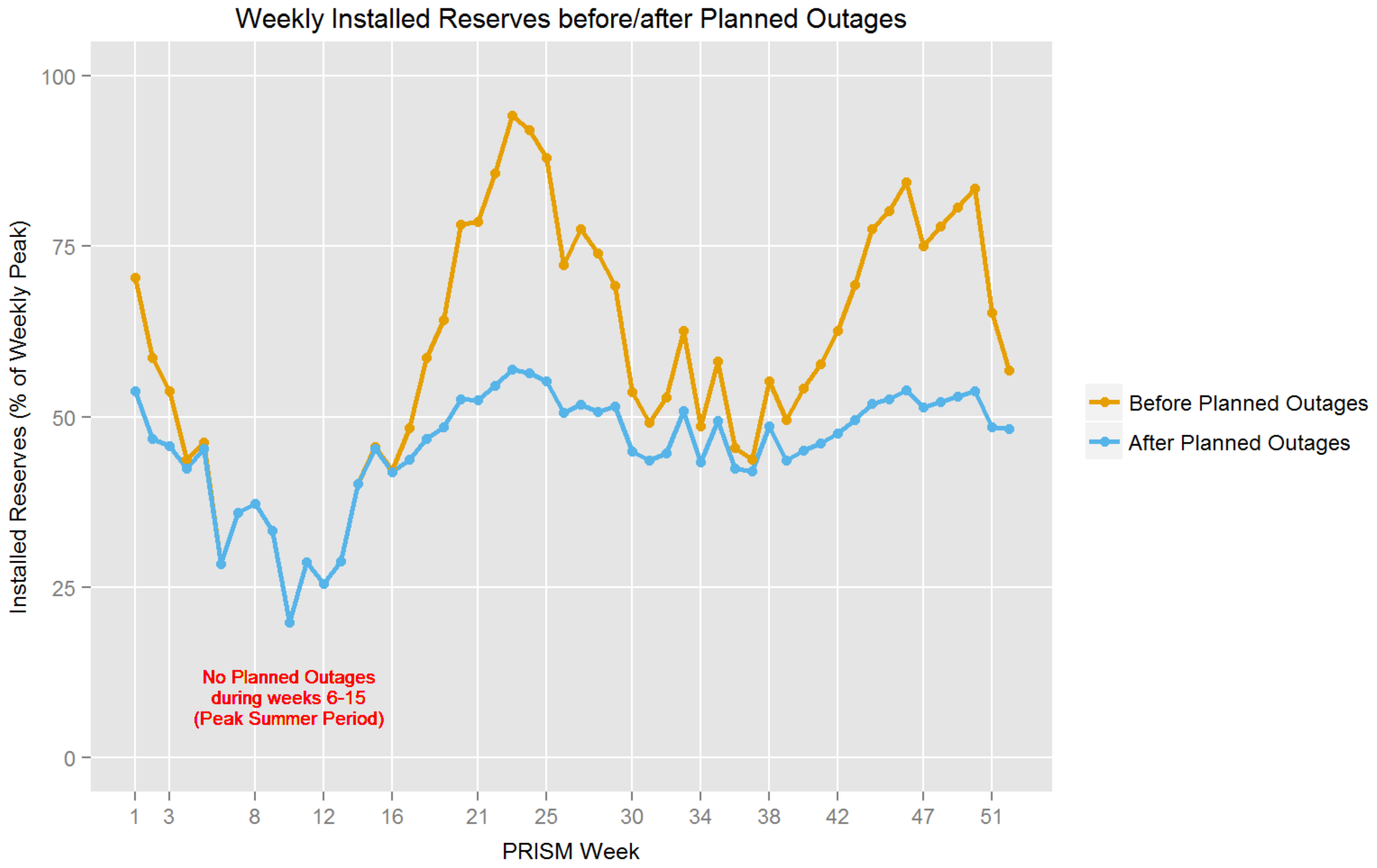
Unit Type & Primary Fuel Category	Gen Class Key	POF Weeks/Year	EFORd	EEFORd	XEFORd	EMOF
FOSSIL All Fuel Types All Sizes	1	4	11.99%	12.83%	11.25%	2
FOSSIL All Fuel Types 001-099	2	3	12.71%	13.36%	12.14%	2
FOSSIL All Fuel Types 100-199	3	3	12.71%	13.36%	12.14%	2
FOSSIL All Fuel Types 200-299	4	5	11.56%	12.65%	10.48%	2
FOSSIL All Fuel Types 300-399	5	5	11.56%	12.65%	10.48%	2
FOSSIL All Fuel Types 400-599	6	5	11.56%	12.65%	10.48%	2
FOSSIL All Fuel Types 600-799	7	5	11.56%	12.65%	10.48%	2
FOSSIL All Fuel Types 800-999	8	5	8.33%	9.25%	8.18%	2
FOSSIL All Fuel Types 1000 Plus	9	5	8.33%	9.25%	8.18%	2
FOSSIL Coal Primary All Sizes	10	4	11.99%	12.83%	11.25%	2
FOSSIL Coal Primary 001-099	11	3	12.71%	13.36%	12.14%	2
FOSSIL Coal Primary 100-199	12	3	12.71%	13.36%	12.14%	2
FOSSIL Coal Primary 200-299	13	5	11.56%	12.65%	10.48%	2
FOSSIL Coal Primary 300-399	14	5	11.56%	12.65%	10.48%	2
FOSSIL Coal Primary 400-599	15	5	11.56%	12.65%	10.48%	2
FOSSIL Coal Primary 600-799	16	5	11.56%	12.65%	10.48%	2
FOSSIL Coal Primary 800-999	17	5	8.33%	9.25%	8.18%	2
FOSSIL Coal Primary 1000 Plus	18	5	8.33%	9.25%	8.18%	2
FOSSIL Oil Primary All Sizes	19	4	11.99%	12.83%	11.25%	2
FOSSIL Oil Primary 001-099	20	3	12.71%	13.36%	12.14%	2
FOSSIL Oil Primary 100-199	21	3	12.71%	13.36%	12.14%	2
FOSSIL Oil Primary 200-299	22	5	11.56%	12.65%	10.48%	2
FOSSIL Oil Primary 300-399	23	5	11.56%	12.65%	10.48%	2
FOSSIL Oil Primary 400-599	24	5	11.56%	12.65%	10.48%	2
FOSSIL Oil Primary 600-799	25	5	11.56%	12.65%	10.48%	2
FOSSIL Oil Primary 800-999	26	5	8.33%	9.25%	8.18%	2
FOSSIL Gas Primary All Sizes	28	4	11.99%	12.83%	11.25%	2
FOSSIL Gas Primary 001-099	29	3	12.71%	13.36%	12.14%	2
FOSSIL Gas Primary 100-199	30	3	12.71%	13.36%	12.14%	2
FOSSIL Gas Primary 200-299	31	5	11.56%	12.65%	10.48%	2
FOSSIL Gas Primary 300-399	32	5	11.56%	12.65%	10.48%	2
FOSSIL Gas Primary 400-599	33	5	11.56%	12.65%	10.48%	2
FOSSIL Gas Primary 600-799	34	5	11.56%	12.65%	10.48%	2
FOSSIL Gas Primary 800-999	35	5	8.33%	9.25%	8.18%	2
FOSSIL Lignite Primary All Sizes	37	4	11.99%	12.83%	11.25%	2

Unit Type & Primary Fuel Category	Gen Class Key	POF Weeks/Year	EFORd	EEFORd	XEFORd	EMOF
NUCLEAR All Types	38	3	1.99%	2.18%	1.67%	0
NUCLEAR All Types	39	3	1.99%	2.18%	1.67%	0
NUCLEAR All Types	40	3	1.99%	2.18%	1.67%	0
NUCLEAR All Types	41	3	1.99%	2.18%	1.67%	0
NUCLEAR PWR All Sizes	42	3	1.99%	2.18%	1.67%	0
NUCLEAR PWR 400-799	43	3	1.99%	2.18%	1.67%	0
NUCLEAR PWR 800-999	44	3	1.99%	2.18%	1.67%	0
NUCLEAR PWR 1000 Plus	45	3	1.99%	2.18%	1.67%	0
NUCLEAR BWR All Sizes	46	3	1.99%	2.18%	1.67%	0
NUCLEAR BWR 400-799	47	3	1.99%	2.18%	1.67%	0
NUCLEAR BWR 800-999	48	3	1.99%	2.18%	1.67%	0
NUCLEAR BWR 1000 Plus	49	3	1.99%	2.18%	1.67%	0
NUCLEAR CANDU All Sizes	50	3	1.99%	2.18%	1.67%	0
JET ENGINE All Sizes	51	1	13.31%	13.70%	11.07%	1
JET ENGINE 001-019	52	1	16.07%	16.48%	14.88%	1
JET ENGINE 20 Plus	53	1	15.12%	15.55%	11.68%	1
GAS TURBINE All Sizes	54	1	13.31%	13.70%	11.07%	1
GAS TURBINE 001-019	55	1	16.07%	16.48%	14.88%	1
GAS TURBINE 020-049	56	1	15.12%	15.55%	11.68%	1
GAS TURBINE 50 Plus	57	2	10.22%	10.56%	8.16%	1
COMBINED CYCLE All Sizes	58	4	4.98%	5.52%	4.58%	1
HYDRO All Sizes	59	2	11.21%	10.93%	9.45%	2
HYDRO 001-029	60	2	11.21%	10.93%	9.45%	2
HYDRO 30 Plus	61	2	11.21%	10.93%	9.45%	2
PUMPED STORAGE All Sizes	62	5	2.33%	2.64%	1.75%	1
MULTIBOILER/MULTI-TURBINE All Sizes	63	4	11.99%	12.83%	11.25%	2
DIESEL Landfill	64	0	16.98%	16.42%	16.23%	1
DIESEL All Sizes	65	0	7.06%	7.63%	6.13%	2
FOSSIL Oil/Gas Primary All Sizes	66	4	11.99%	12.83%	11.25%	2
FOSSIL Oil/Gas Primary 001-099	67	3	12.71%	13.36%	12.14%	2
FOSSIL Oil/Gas Primary 100-199	68	3	12.71%	13.36%	12.14%	2
FOSSIL Oil/Gas Primary 200-299	69	5	11.56%	12.65%	10.48%	2
FOSSIL Oil/Gas Primary 300-399	70	5	11.56%	12.65%	10.48%	2
FOSSIL Oil/Gas Primary 400-599	71	5	11.56%	12.65%	10.48%	2
FOSSIL Oil/Gas Primary 600-799	72	5	11.56%	12.65%	10.48%	2
FOSSIL Oil/Gas Primary 800-999	73	5	8.33%	9.25%	8.18%	2
Wind All sizes	74	0	0.00%	0.00%	0.00%	0
Solar All sizes	75	0	0.00%	0.00%	0.00%	0

Input #2: Capacity Model – Planned Outages Schedule

- Objective in the development of the schedule
  - Levelizing weekly reserves (in PRISM and MARS)
- Each unit has a EPOF in weeks/year
  - Current weighted average EPOF: ~4 weeks/year
- The “levelizing reserves” objective places more planned outages in weeks that have larger reserves (in PJM’s case, outside of summer period)

Input #2: Capacity Model – Planned Outages Schedule



Input #2: Capacity Model – Available Capacity Distribution

- The availability of each unit is assumed to have an independent Bernoulli distribution

  Prob (Unit Online) = 1 - EEFORd

  Prob (Unit Offline) = EEFORd

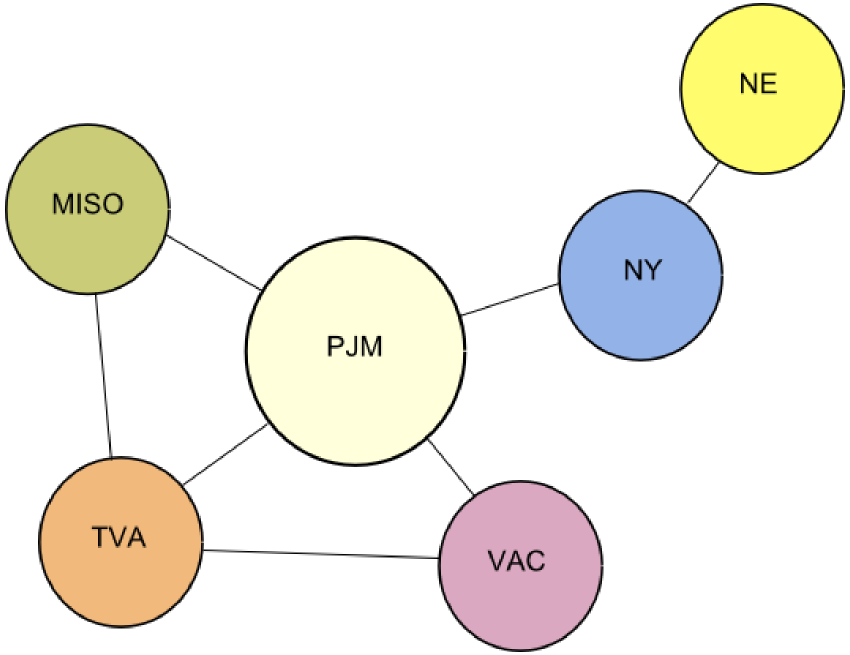
- The Available Capacity Distribution is calculated for each week by summing the Bernoulli Distributions of the units not on planned outage during the week under consideration
- Sum of Bernoulli Distributions is performed via convolution

Input #2: Capacity Model – Ambient Derations

- Rationale
  - Hot and humid summer conditions (above 50/50) limits MW output from certain types of generators
  - Units can operate at this reduced output without incurring a GADS outage event (event is not included in EFORd value)
- MW Impact
  - It has been assumed for several years that the amount of ambient derations throughout the PJM footprint is 2,500 MW
- Modeling in RRS
  - 2,500 MW are assumed to be on planned outage during the peak summer period (10 weeks)

Input #3: World Region

- PJM and its neighbors

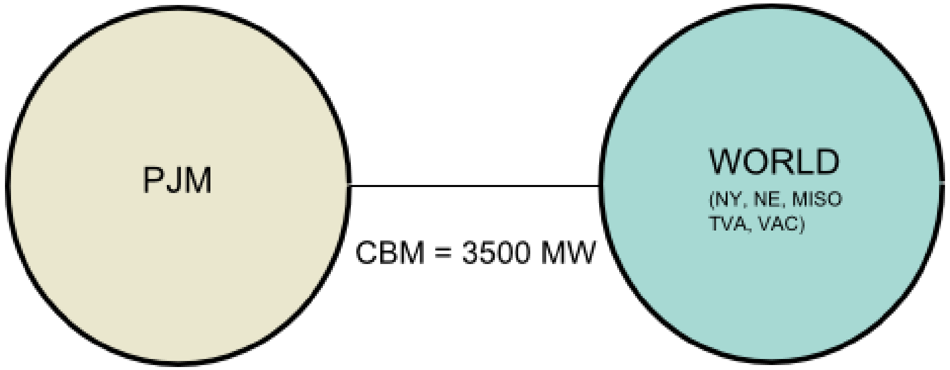


Though ISO-NE is not a direct neighbor, PJM includes ISO-NE in the World due to the emergency assistance they have provided in the past.

Input #3: World Region

- PRISM allows for modeling only two regions.
- Due to this limitation, the neighboring regions are condensed into a single region: the World.
- As with PJM, the World requires a load model and a capacity model
- To develop the load model,
  - Historical daily peak loads of the 5 World regions are pooled together
  - World LMs are derived for the time-periods shortlisted in the Load Model Selection Procedure
  - PJM-World Load Diversity check is performed. A time-period is selected

- Capacity Benefit Margin (CBM)



CBM is the limit on the amount of power that can be transferred between PJM and the World and vice-versa in a two-area RRS case.

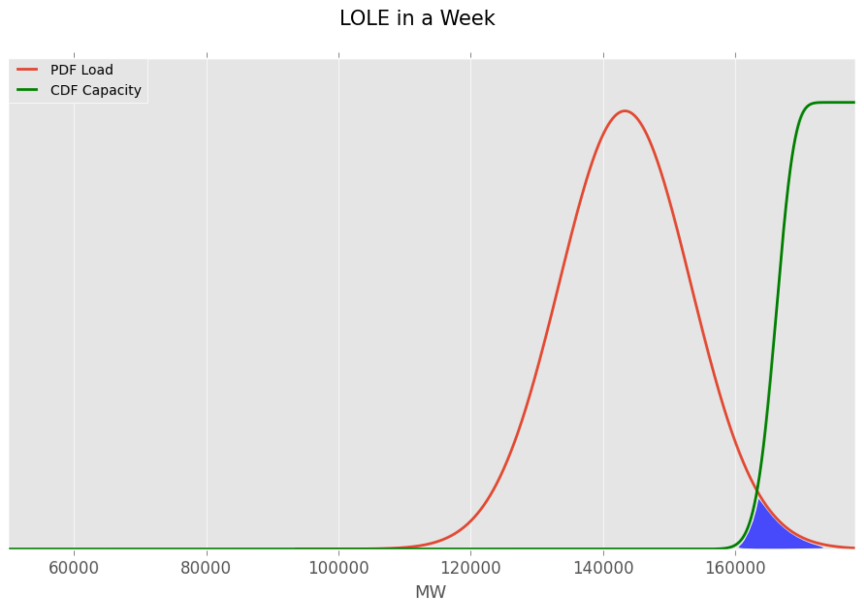
The CBM value of 3,500 MW is specified in the PJM Reliability Assurance Agreement (RAA), Schedule 4. PJM's additional importing capability is used in the marketplace.

- If X = Available Capacity Distribution at week t
- and Y = Load Distribution at week t
- Then a **Loss of Load Event** (LOLE) takes place when X < Y
  - LOLE is defined when the margin is 0 MW or less (Margin = X – Y)
- The IRM is computed as
  - » IRM = Total Installed Capacity / Solved Annual Peak Load

when the Solved Annual Peak Load is such that

Total LOLE = $\sum_{w=1}^{52} E(X < Y) = 0.1\ days/year$

- Let's start with the Single Area RRS Case.



For each week, we need to compute the probability that load exceeds available capacity P (X < Y) (blue area in the figure).

The expected value of load exceeding available capacity in a week is then given by,

$$E(X < Y) = 5 \times 1 \times P(X < Y)$$

- 1 is because we are computing expected value
- 5 is because we have a daily peak load distribution aggregated by week (and there are 5 weekdays in a week)

Procedure to Calculate LOLE, Find IRM/FPR

- Mathematically,

PDF Load:
Mean = 143298
StDev = 9943

Scenario	Load	Probability
4.2	185057	0.000033
3.78	180881	0.000145
3.36	176705	0.000638
2.94	172529	0.002351
2.52	168353	0.007273
2.1	164178	0.01894
1.68	160002	0.0414
1.26	155826	0.07608
0.84	151650	0.11749
0.42	147474	0.15248
0	143298	0.16634
-0.42	139122	0.15248
-0.84	134946	0.11749
-1.26	130770	0.07608
-1.68	126594	0.0414
-2.1	122418	0.01894
-2.52	118242	0.007273
-2.94	114066	0.002351
-3.36	109890	0.000638
-3.78	105714	0.000145
-4.2	101538	0.000033

CDF Capacity (in increments of 10 MW)

Total Available Capacity	Cumulative Prob
178000	1.000
177000	1.000
176000	1.000
175000	1.000
174000	1.000
172520	1.000
173000	1.000
172000	0.999
171000	0.993
170000	0.971
168350	0.856
169000	0.916
168000	0.816
167000	0.670
166000	0.500
164170	0.222
165000	0.336
164000	0.202
163000	0.109
162000	0.053
161000	0.023
160000	0.009
159000	0.003
158000	0.001

E (X < Y):

185057 -> 5 x 1 x 0.000033 x 1.000 = 0.000165
180881 -> 5 x 1 x 0.000145 x 1.000 = 0.000725
176705 -> 5 x 1 x 0.000638 x 1.000 = 0.00319
172529 -> 5 x 1 x 0.002351 x 1.000 = 0.011755
168353 -> 5 x 1 x 0.007273 x 0.856 = 0.031128
164178 -> 5 x 1 x 0.01894 x 0.222 = 0.021023
160002 -> 5 x 1 x 0.0414 x 0.009 = 0.001863
155826 -> 5 x 1 x 0.07608 x ~0 = 0
……………………………………………………
101538 -> 5 x 0 x 0.000033 x 0 = 0

TOTAL = 0.069849 days/year

Procedure to Calculate LOLE, Find IRM/FPR

- We repeat the procedure shown in the previous slide for the remaining 51 weeks
- When we have that the Expected LOLE across the 52 weeks is equal to 0.1 days/year, we calculate
    - Single Area IRM = Total Installed Capacity / Solved Annual Peak Load
- The Single Area IRM is used to compute the CBOT
- The Two-Area IRM is the IRM that gets all the attention

Procedure to Calculate LOLE, Find IRM/FPR

- Two-Area IRM (or simply, IRM)
  - Theory is similar to LOLE computation in Single Area Case
  - However, we now need to include the help from the World
  - The Two-Area LOLE in a week is calculated as,

$$E\,(X < Y) = 5 \times 1 \times [\, P(X < Y) \mathbf{- P(Help\ from\ World)}\,]$$

with P(Help from World) = P (PJM needing N MWs) x P (World able to supply N MWs within the CBM constraint)

  - Identical computations are performed to calculate the World LOLE

Procedure to Calculate LOLE, Find IRM/FPR

- Single Area RRS Case

	Year	ALM Sub Num	Run	Iter-ation	Area	Load Level	Week Num	Primary Load	Install Cap	Install Pct	Avail Pct	Tie Size	RI
First run	2019	.	1	1	1	0	10	150283	182530	21.457517	19.800643	3500	30.323166
Final run	2019	.	20	1	1	0	10	154464	182530	18.16993	16.557903	3500	9.9931317

Single Area IRM = 18.16993 ~ 18.2

- Two Area RRS Case

	Year	ALM Sub Num	Run	Iter-ation	Area	Load Level	Week Num	Primary Load	Install Cap	Install Pct	Avail Pct	Tie Size	RI
First run PJM	2019	.	1	1	1	0	10	150283	182530	21.457517	19.800643	3500	30.512648
First run World	2019	.	1	1	2	0	12	245919	279090	13.488588	13.488588	3500	2.299218
Final run PJM	2019	.	9	2	1	0	10	156731.61	182530	16.459985	14.871282	3500	9.996217
Final run World	2019	.	9	2	2	0	12	237704.46	279090	17.410696	17.410696	3500	9.9964503

Two Area IRM = 16.459985 ~ 16.5

RI: Reliability Index

RI = 1/LOLE

We always round the IRM to the first decimal point

Capacity Benefit of Ties (CBOT) = Single Area IRM – Two Area IRM = 18.2 – 16.5 = 1.7

- From the IRM to the FPR
  - FPR is used to develop the Reliability Requirement in RPM
  - FPR is computed as
    - » FPR = IRM x (1- Pool Avg XEFORd)
  - To derive the Pool Avg XEFORd, we compute a capacity-weighted average XEFORd with the units in the RRS case for the year under study
  - FPR = (1+16.5%) x (1-6.6%) = 1.165 x 0.934 = 1.0881 (8.81%)