PIE Project, Report 7.
Model reduction and translation for coordinated expansion planning studies.

Task G7: Reduced network model

Yanda Jiang, Zohreh Parvini, Ali Jahanbani, Colin Christy, James McCalley

IOWA STATE UNIVERSITY

Contents

A. Background

TENSOR ANALYSIS
OF
NETWORKS
By
GABRIEL KRON
Copyright, 1939, by
The General Electric Company

Equivalent Circuits for Power-Flow Studies
1949, Volume 68 AIEE Transactions
J. B. WARD

A lot more

Some more

SUBTRANSMISSION REDUCTION FOR VOLTAGE INSTABILITY ANALYSIS
James D. McCalley, Member John F. Dorsey, Sr Member
Georgia Institute of Technology
James F. Luini, Fellow R. Peter Mackin, Member Gerardo H. Molina
Pacific Gas and Electric Company
IEEE Transactions on Power Systems, March, 1993

DEVELOPMENT OF DYNAMIC EQUIVALENTS FOR TRANSIENT STABILITY STUDIES
EPRI EL-456
(Research Project 763)
April 1977
Prepared by
SYSTEMS CONTROL, INC.
1801 Page Mill Road
Palo Alto, California 94304
PRINCIPAL INVESTIGATORS
Robin Podmore
Alain Germond

• • •

ELSEVIER
Electric Power Systems Research
Volume 227, Part A, February 2024, 109917

➔144 references

Power system reduction techniques for planning and stability studies: A review

Lahiru Aththanayake [a], Nasser Hosseinzadeh [a], Ameen Gargoom [a], Hassan Haes Alhelou [b]

➔Some on reduction for expansion planning, but it is light

B. Motivation

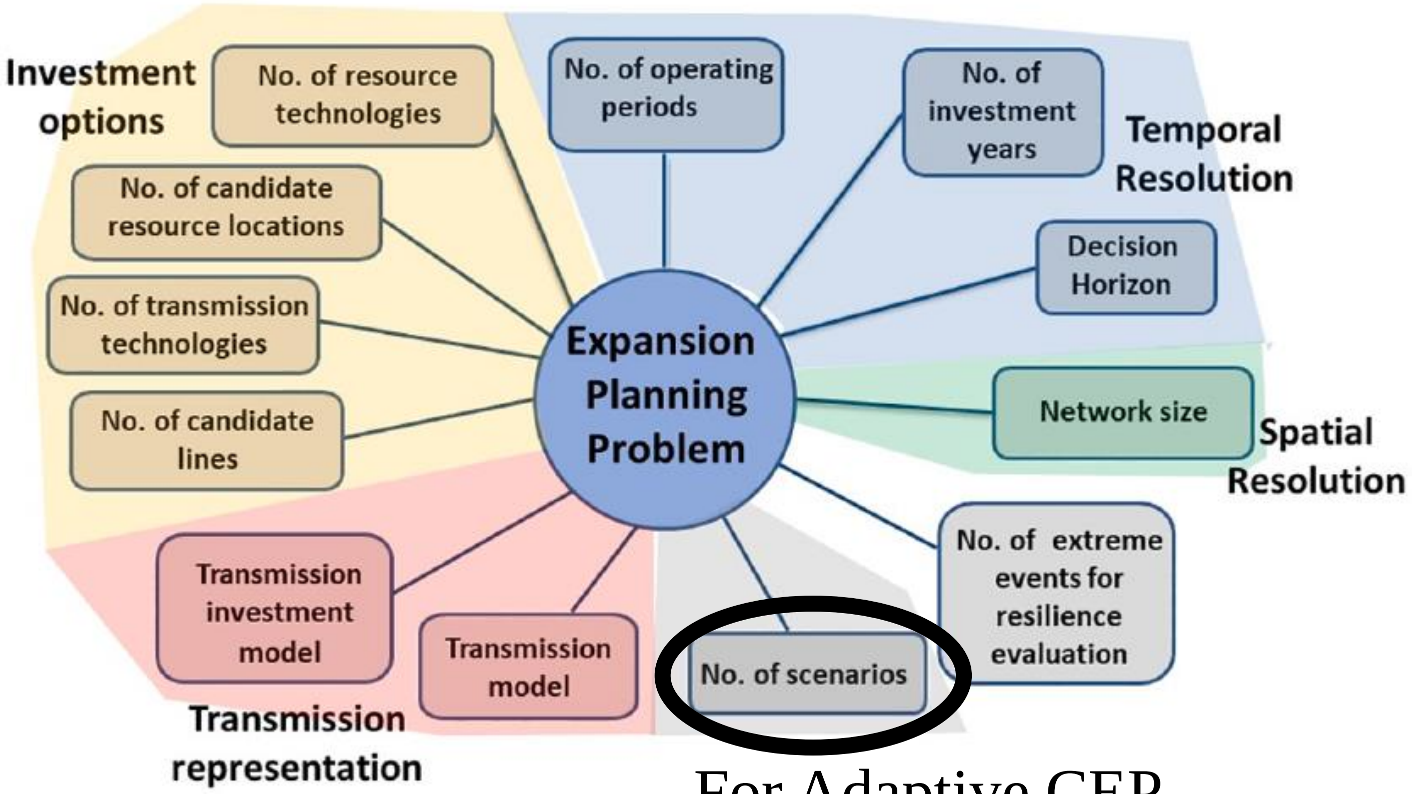
<u>Coordinated expansion planning (CEP)</u>: a computationally intensive optimization problem

Minimize:

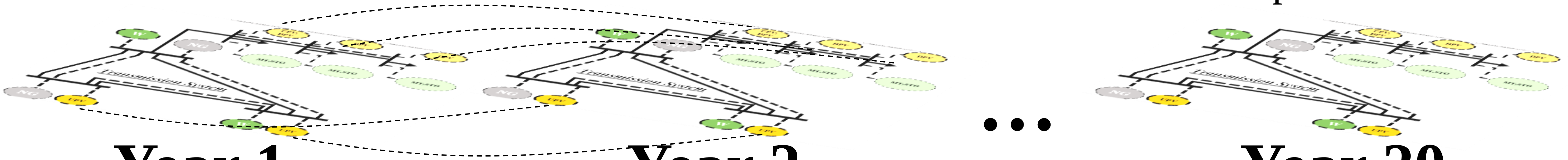
Σ_t NetPresentWorth {CoreCosts($\underline{x}$(t))
+{OpCost($\underline{x}$(t))}

Subject to:

constraints **(ntwrk, operations, envrnmnt, invstmnts)**



For Adaptive CEP



Year 1 **Year 2** **Year 20**

C. Overall reduction process

<u>OBJECTIVES OF THIS PROCESS</u>:

- MINIMIZE CEP COMPUTE TIME
- MAXIMIZE EXPANSION FIDELITY

1. PREPROCESS
a. Trim & map
b. Identify study sys
c. Reduce ext system

2. DIVIDE
a. Key branches
b. Zones

3. RETAIN
Identify buses to keep.

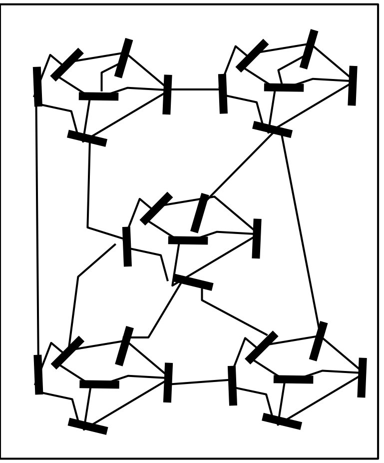
4. ELIMINATE
Apply Ward to each zone.

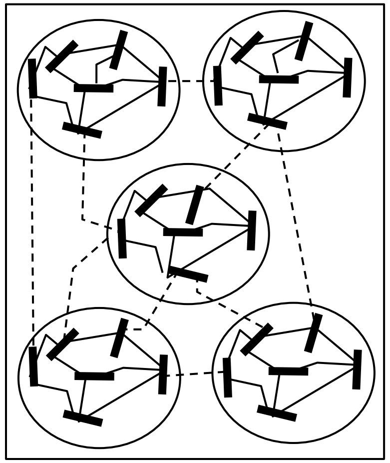
5. AGGREGATE
a. Topology-based
b. QG

6. ESTIMATE
a. Capacities
b. Exp cost

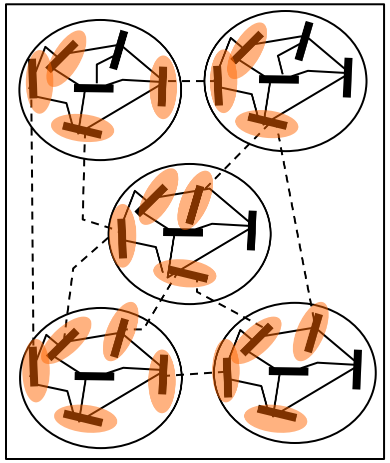
7. CEP

8. TRANSLATION

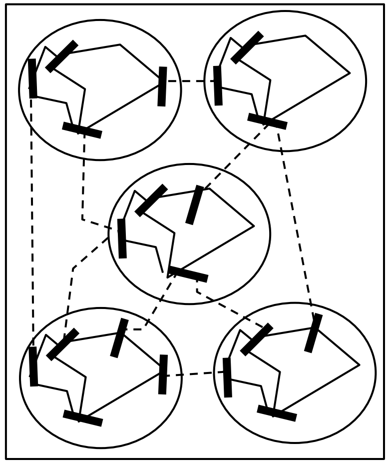




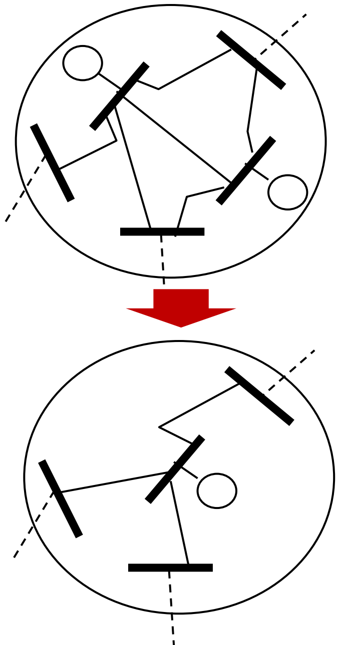
Fast CEP & MST



Genetic Alg: to min DVs



Guided Ward Elimination



Steps 4, 5 create equiv. branches but not capacities or exp cost.

Step 7 expands a reduced system; Step 8 identifies expansion on full system.

D. Individual Steps: Key branch/zone identfication

1. PREPROCESS
a. Trim & map
b. Identify study sys
c. Reduce ext system

→ **2. DIVIDE**
a. Key branches
b. Zones

→ **3. RETAIN**
Identify buses to keep.

→ **4. ELIMINATE**
Apply Ward to each zone.

→ **5. AGGREGATE**
a. Topology-based
b. QG

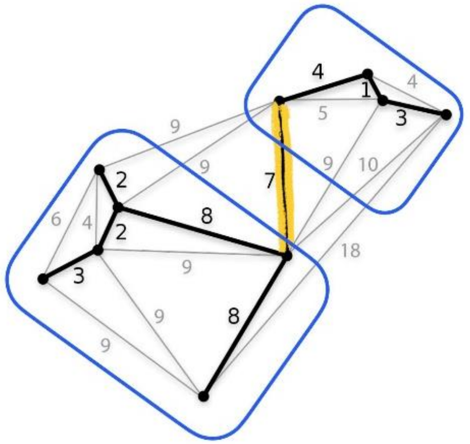
→ **6. ESTIMATE**
a. Capacities
b. Exp cost

→ **7. CEP** → **8. TRANSLATION**

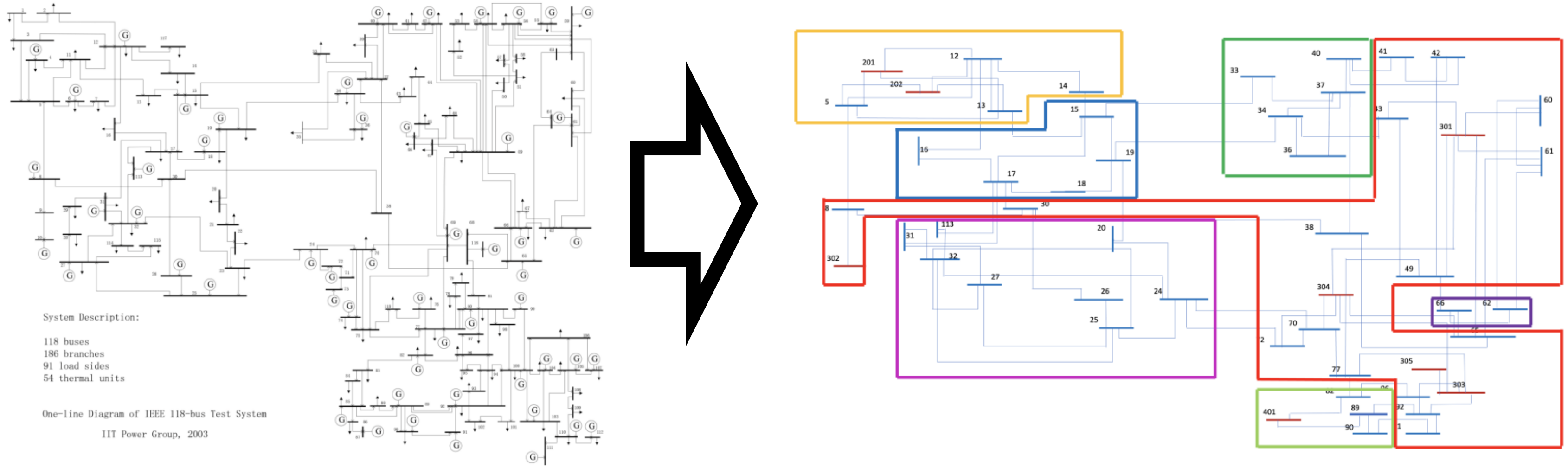
CONCEPT:
1. There are ***key branches*** we know are investment targets.
2. We divide system into zones based on key branches.
3. Each zone may then be reduced into a zonal subsystem.

APPROACH:
Use minimum spanning tree (MST).

Conceptual illustration



188 IEEE Test Case



D. Individual Steps: Guided Ward Elimination

1. PREPROCESS
a. Trim & map
b. Identify study sys
c. Reduce ext system

2. DIVIDE
a. Key branches
b. Zones

3. RETAIN
Identify buses to keep.

4. ELIMINATE
Apply Ward to each zone.

5. AGGREGATE
a. Topology-based
b. QG

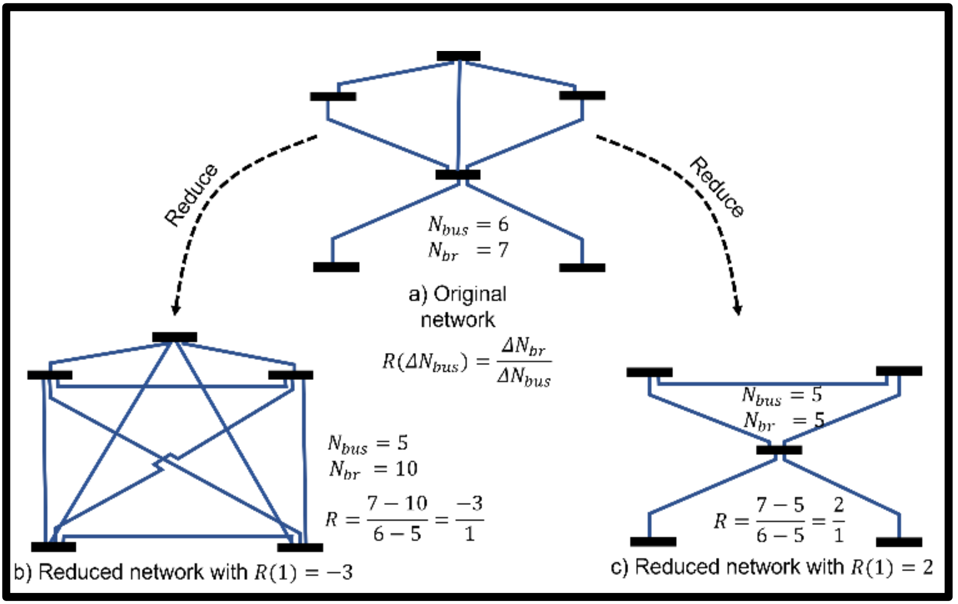
6. ESTIMATE
a. Capacities
b. Exp cost

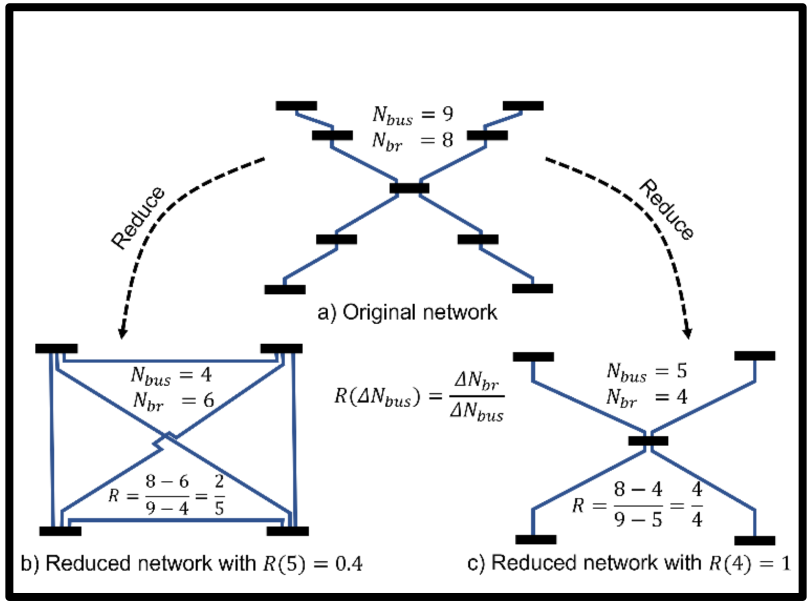
7. CEP

8. TRANSLATION

CONCEPT:

1. CEP run-time is sensitive to number of branches.
2. Choice of buses to eliminate (left) & number of buses to eliminate (right) affects branch to bus reduction ratio R.





APPROACH:

Use GA to minimize

$$f(\alpha \times N_{buses} + \beta \times N_{branches})$$

- α and β chosen for a given CEP model and zone's network structure (exploring spectral graph theory).
- GA is seeded with solutions from other methods, e.g., lowest connection degree.

D. Individual Steps : Topology-based aggregation

1. PREPROCESS
a. Trim & map
b. Identify study sys
c. Reduce ext system

2. DIVIDE
a. Key branches
b. Zones

3. RETAIN
Identify buses to keep.

4. ELIMINATE
Apply Ward to each zone.

5. AGGREGATE
a. Topology-based (TB)
b. QG

6. ESTIMATE
a. Capacities
b. Exp cost

7. CEP

8. TRANSLATION

CONCEPT:

1. For each zone, aggregation is performed on generator buses, after elimination of most load buses.
2. Two gen buses are aggregated only if they are connected to the same boundary buses.
3. Thevenin impedance between each pair of boundary buses should be the same in reduced and full network.

APPROACH:

Select impedances of new branches between boundary buses and aggregated bus to minimize

$$\sum_j \left(Z_{BB\ pair\ j}^{full} - Z_{BB\ pair\ j}^{reduced} \right)^2$$

We also check fidelity and disaggregate if needed.
A modified QG method [1] with fidelity checks is also used to achieve more reduction.

[1] D. Shi and D. Tylavsky, (2014). A novel bus-aggregation-based structure-preserving power system equivalent. IEEE Trans Power Systems, 30(4):1977–1986

D. Individual Steps: Capacity estimation

1. PREPROCESS
a. Trim & map
b. Identify study sys
c. Reduce ext system

2. DIVIDE
a. Key branches
b. Zones

3. RETAIN
Identify buses to keep.

4. ELIMINATE
Apply Ward to each zone.

5. AGGREGATE
a. Topology-based (TB)
b. QG

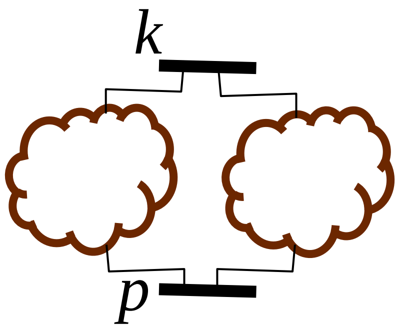
6. ESTIMATE
a. Capacities
b. Exp cost

7. CEP

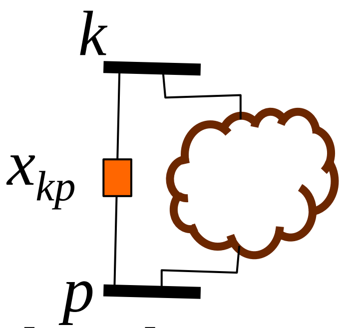
8. TRANSLATION

CONCEPT: .

Capacity of equivalent branch *kp* in reduced network corresponds to maximum angle separation from *k* to *p* in full network.



Full System



Reduced System with equiv. branch *kp* and reactance x_{kp}

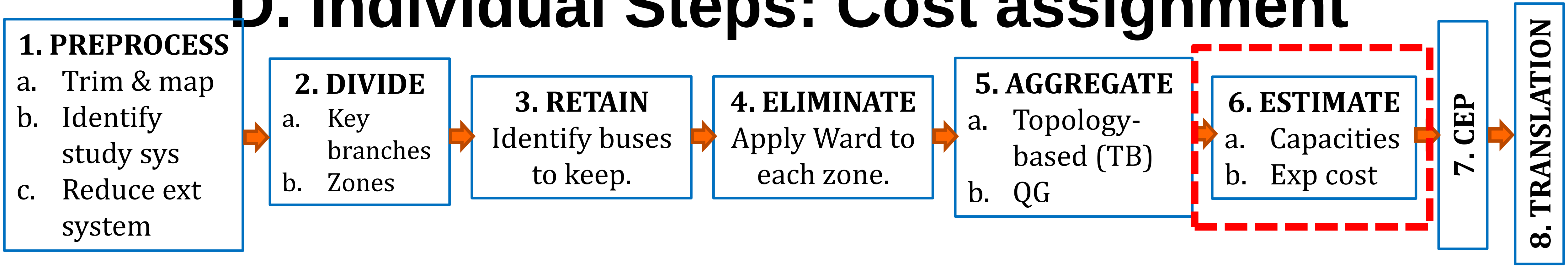
APPROACH:

$$\max_{\underline{P},\underline{L}} S_{base} \frac{\theta_k - \theta_p}{x_{kp}}$$

subject to :

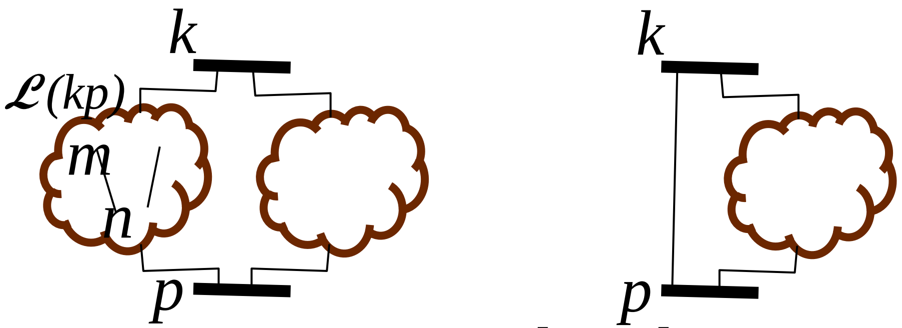
$$\begin{array}{lll} \textit{calculated flows} & f_{ij} = S_{base} \dfrac{\theta_i - \theta_j}{x_{ij}} & \forall \quad (i,j) \\ \textit{limits on flows} & f_{ij}^{min} \le f_{ij} \le f_{ij}^{max} & \forall \quad (i,j) \\ \textit{nodal power balance} & P_i - \sum_i f_{ij} + \sum_j f_{ji} = L_i & \forall \quad i \end{array}$$

D. Individual Steps: Cost assignment



CONCEPT: .

An equivalent branch connected between buses *k* and *p* has a cost contribution from each branch *mn* it represents. That cost contribution is found via PTDF$_k$-PTDF$_p$ as the amount of flow on each represented branch mn when 1 MW is injected at bus *k* and withdrawn at bus *p*.



Full System

Reduced System with equiv. branch *kp*

APPROACH:

$$\frac{\Delta Cost_{kp}}{\Delta Cap_{kp}} = \sum_{mn\in\mathcal{L}(kp)} f_{mn} \times \frac{\Delta Cost_{mn}}{\Delta Cap_{mn}}$$

f_{mn} = element of PTDF$_k$-PTDF$_p$ corresponding to branch *mn*.

Expansion cost of eliminated branch represented by *kp*.

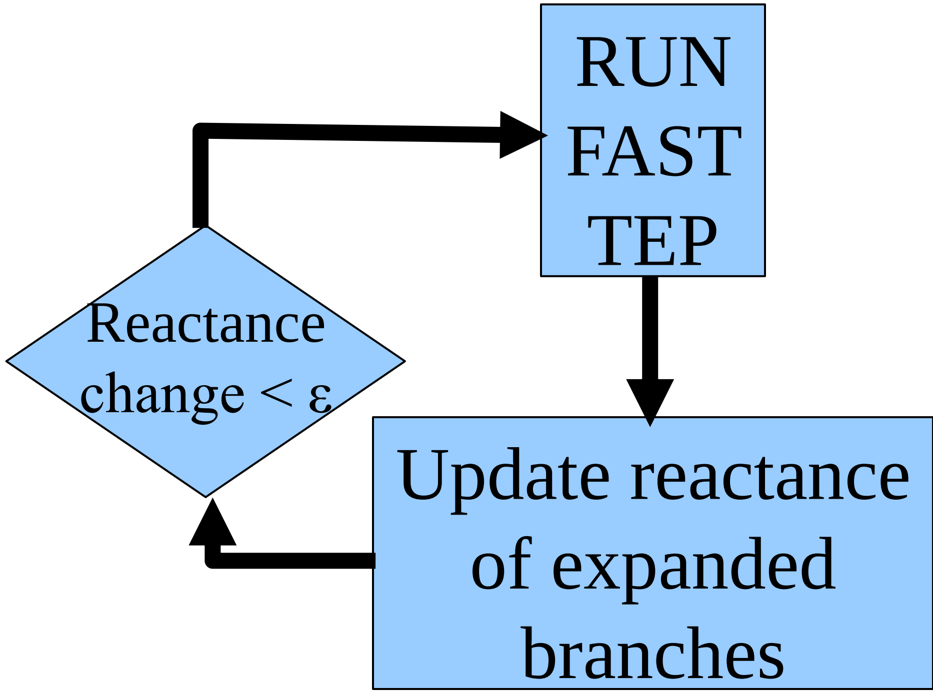
D. Individual Steps: CEP with Translation

1. PREPROCESS
   a. Trim & map
   b. Identify study sys
   c. Reduce ext system
2. DIVIDE
   a. Key branches
   b. Zones
3. RETAIN
   Identify buses to keep.
4. ELIMINATE
   Apply Ward to each zone.
5. AGGREGATE
   a. Topology-based (TB)
   b. QG
6. ESTIMATE
   a. Capacities
   b. Exp cost
7. CEP
8. TRANSLATION

CONCEPT:

- CEP identifies G&T expansions on reduced model;
  ➔Need to “translate” to full model.
- Heuristic gen-mapping:
  - Existing gen maps to original buses;
  - New gen maps to buses within zone of reduced bus.
- Key-branch expansions used directly;
- A “fast TEP” is then run:
  - 1 period
  - Fixed reactance (capacity changes but reactance does not)
  - Iterative

APPROACH:



E. Illustrative Results

1. PREPROCESS
a. Trim & map
b. Identify study sys
c. Reduce ext system

2. DIVIDE
a. Key branches
b. Zones

3. RETAIN
Identify buses to keep.

4. ELIMINATE
Apply Ward to each zone.

5. AGGREGATE
a. Topology-based (TB)
b. QG

6. ESTIMATE
a. Capacities
b. Exp cost

7. CEP

8. TRANSLATION

Step	IEEE 118 – 21 Zones		RTE 617 – 50 zones	
	# buses	ObjRed/ ObjFull	# buses	ObjRed/ ObjFull
Full model	118		617	
After Step 1 (trimming)	109		376	
After Step 4 (Ward) + Step 6	74	0.9964	197	1.0009
After Step 5a (TB agg) + Step 6	61	0.9782	181	1.0043
After Steps 5b (QG agg) + Step 6	37	0.9802	94	0.9836
After Step 8 (Translation)	118	1.5727	617	1.162

5. Conclusions

1. PREPROCESS
a. Trim & map
b. Identify study sys
c. Reduce ext system

2. DIVIDE
a. Key branches
b. Zones

3. RETAIN
Identify buses to keep.

4. ELIMINATE
Apply Ward to each zone.

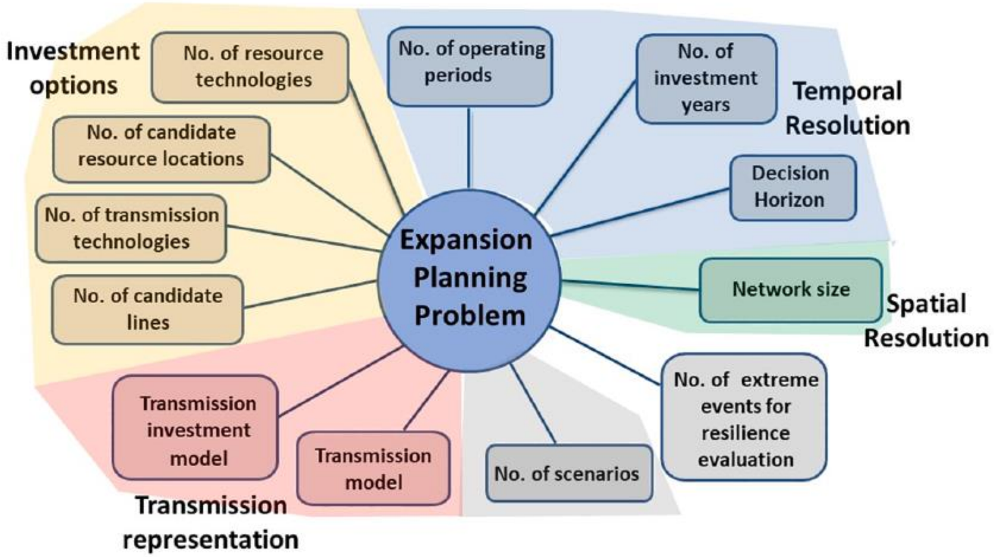
5. AGGREGATE
a. Topology-based (TB)
b. QG

6. ESTIMATE
a. Capacities
b. Exp cost

7. CEP

8. TRANSLATION

1. Expansion planning apps important for electric grid transformation.
2. Network reduction functions enable high fidelity in other dimensions.

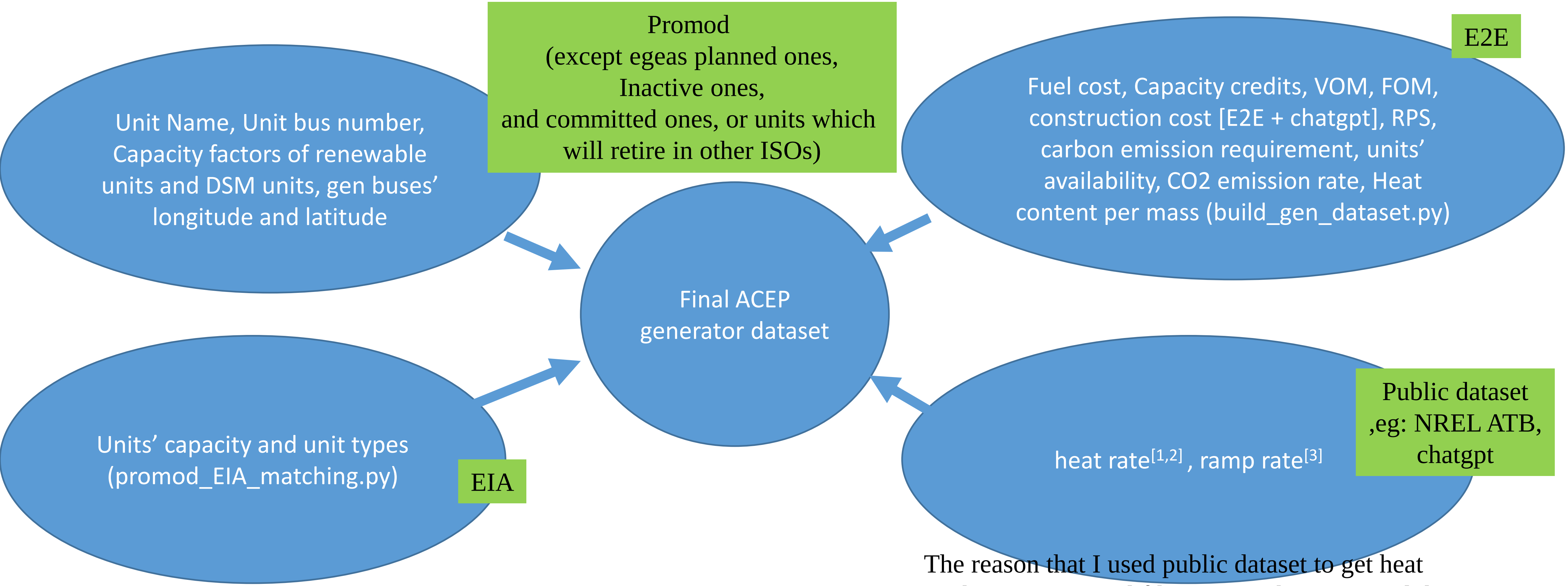


Appendix: Notes on data development

0. Summary
1. Generator data
2. Load data
3. Required reserves
4. Transmission investment
5. DSM

Category	Sheet name	Source and Code to make it
1. Generators	DSM_CF, CF (Capacity factors)	CF folder (shared by James and Jeremy)
	CC_trajectory (Capacity credits)	E2E spreadsheet. (Shared by Nolan.)
	Operational_Capacity, DSM_capacity	Build_gen_dataset.py → Operational_capacity.py
	Fuel_cost	Build_gen_dataset.py → Fuel_cost_processing.py
	New_Availability	Build_gen_dataset.py → Unit_availability.py
	VOM, FOM, Construction_Cost	Build_gen_dataset.py → VOM_FOM_cost_trajectory.py
	Heat rate, ramp rate	Public sources, eg: NREL ATB or chatgpt
2. Load	block level and annual peak load	Built_load_dataset.py
3. Additional auxiliary information	DFac	Egeas
	RPS, CarbonEmRed	Dan Robicheaux
4. Operation information	Needed_reserve (including contingency reserve and regulation reserve)	Yonghong Chen
5. Network information	Transmission system	James Slegers and Jeremy Nash
	Gen and transmission expansion limit	Amy Hackbarth
	Transmission investment cost	Transmission cost estimation document

1. Generator data (E2E, EIA, NERL, Promod)



The reason that I used public dataset to get heat rate is because promod file contains heat rate and thus I am not sure if the heat rate in E2E comes from promod, and thus not allowed for usage.

1. https://iea.blob.core.windows.net/assets/1028bee0-2da1-4d68-8b0a-9e5e03e93690/essentials3.pdf
2. https://www.eia.gov/electricity/annual/html/epa_08_01.html
3. https://www.nrel.gov/docs/fy20osti/77639.pdf

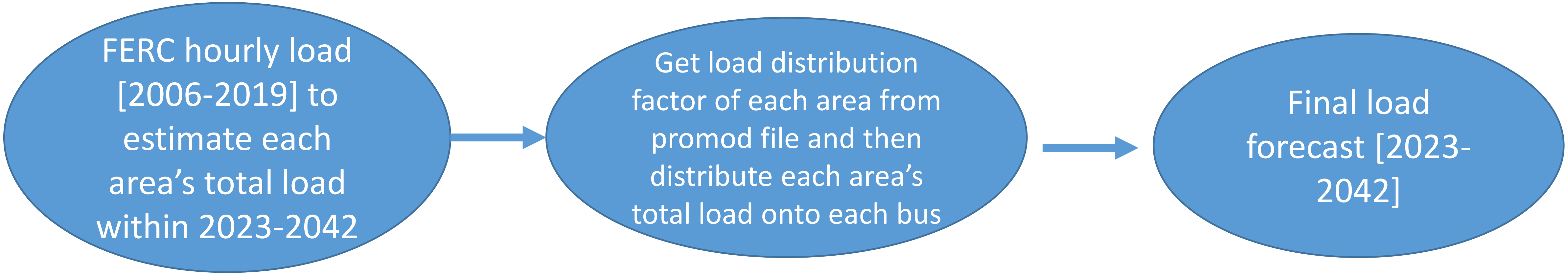
Comments:

- Existing gen units are selected from promod file and some of the property features are extracted from E2E sheet or EIA sheet.
  - In cases where Promod units cannot be located in the E2E data, we will substitute the corresponding economic data from other Promod units of the same type that share similar capacity.
  - Some units are only existed in E2E, but not promod, will be discarded, since their located buses are not known.
  - Some promod units cannot be found from EIA sheet, because they are retired or change to new names. For those units, I used the EIA units which have the most similar names. This represents a trade-off between accuracy and convenience, acknowledging that it may not be 100% precise.
  - Heat rates and ramp rates are identified based on units' types using public datasets, such as NREL ATB or chatgpt etc.

- Newly added units are extracted from E2E sheet.

2. Load (FERC + promod)

Interruptible load and industrial load are included as DSM for peak moment, i.e used to reduce peak load while evaluating planning reserve margin.



- There are 87 areas which have load data from 2006-2020. For those areas, we will just use their block load from 2006-2019 to forecast future load.
- For other areas which only have few years’ historical load data, we will apply the sum of those 87 areas’ load increasing ratio onto these areas’ 2006 load data.
- Load will only increase in MISO region. The external areas’ load will be kept constant from 2023 to 2042.
- There is one problem here. There are 39 MISO areas in total. However, if we use ferc ID, then there are 53 areas will be included, which means 14 additional external areas will be mis-recognized as MISO areas and experience load increase.
- We use mean ratio of peak load in this area over the whole zone over all recorded years to reduced the hourly load.
- For Ferc areas which include multiple promod areas, we use peak load ratio between these areas to identify appropriate load.

  There are 218 ferc_id, among them 50 are in eastern interconnection region. 2885 Areas are included in ferc file, among them 90 are included in promod’s eastern interconnection system.

Load (MISO private data)

Extract each area's load forecast within the planning horizon

Fill up missing years' hourly load of each area by polynomial estimation and try to avoid negative value. (If there is negative load, then try different polynomial degree.)

Use promod load sheet to identify distribution ratio of each area in promod file and allocate forecasted load onto each bus. (Other areas will be ignored.)

Load (public data)

Extract each zone's historical load from 2006-2020. Some of them only have a few years' record.

Begin by converting the data from hourly load data to block level. Afterward, set the load for external zones as the last recorded year and exclusively apply the exponential model to predict the load for MISO zones.

Determine the connection between MISO areas and FERC zones, taking into account that certain FERC zones may be associated with multiple MISO areas. In such cases, utilize the ratio of the combined summer peak and winter peak for the relevant areas to the total peak sum across all areas. This ratio is employed to estimate the load of a specific area from the aggregate block load of the entire zone.

Use promod load sheet to identify distribution ratio of each area in promod file and allocate forecasted load onto each bus. (Other areas will be ignored.)

Annually Peak Load

Load (MISO private data)

Sum hourly load data over whole system and pick out annually peak load from them.

Load (public data)

Utilize the publicly available dataset titled "20230428 LRTP Workshop Item 03b All Futures Load Forecast Summary (MISO)628685.xlsx" to calculate the ratios between F1, F2, and F3 load data and use it to estimate F2 and F3 block load data across the entire planning horizon. Additionally, determine the ratio between peak load and average load and use it to estimate the annual peak load data for F1, F2, and F3.

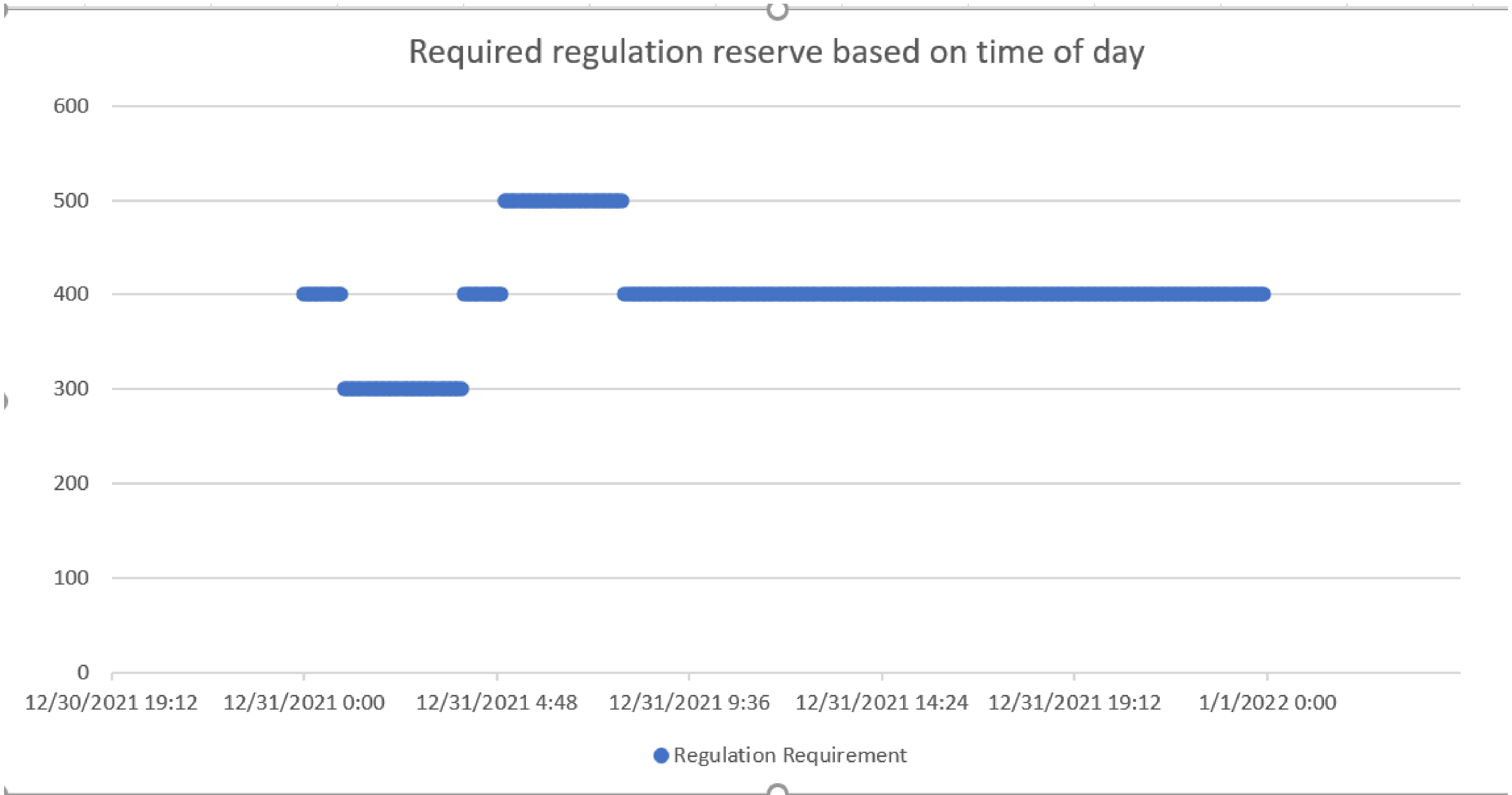
Comments:

- We don’t want to consider some exogenous factors, like economic crisis. Instead, we only want to capture general trend of load increase, which is decided by population increase and industrialization speed etc.
- Seasonality’s impact is reduced after we build load blocks.
- Temporal dependence is not that obvious since residents won’t respond to previous load value like they did in stock market.
- Time series analysis is more appropriate for short-term analysis, while regression is more appropriate for long term. (check reasons)
- Time series is more complicated considering model selection and hyperparameters’ selection. We don’t want to spend too much time here.
- So in a word, I think we can use regression models here.
- Upon comparing the Promod load with the estimated load, I noticed that while they are not identical, they fall within a similar range. Additionally, there is no negative load observed. Hence, I believe it is sufficiently reliable for use.

3. Required reserves

The required regulation reserve (response time 5 min)

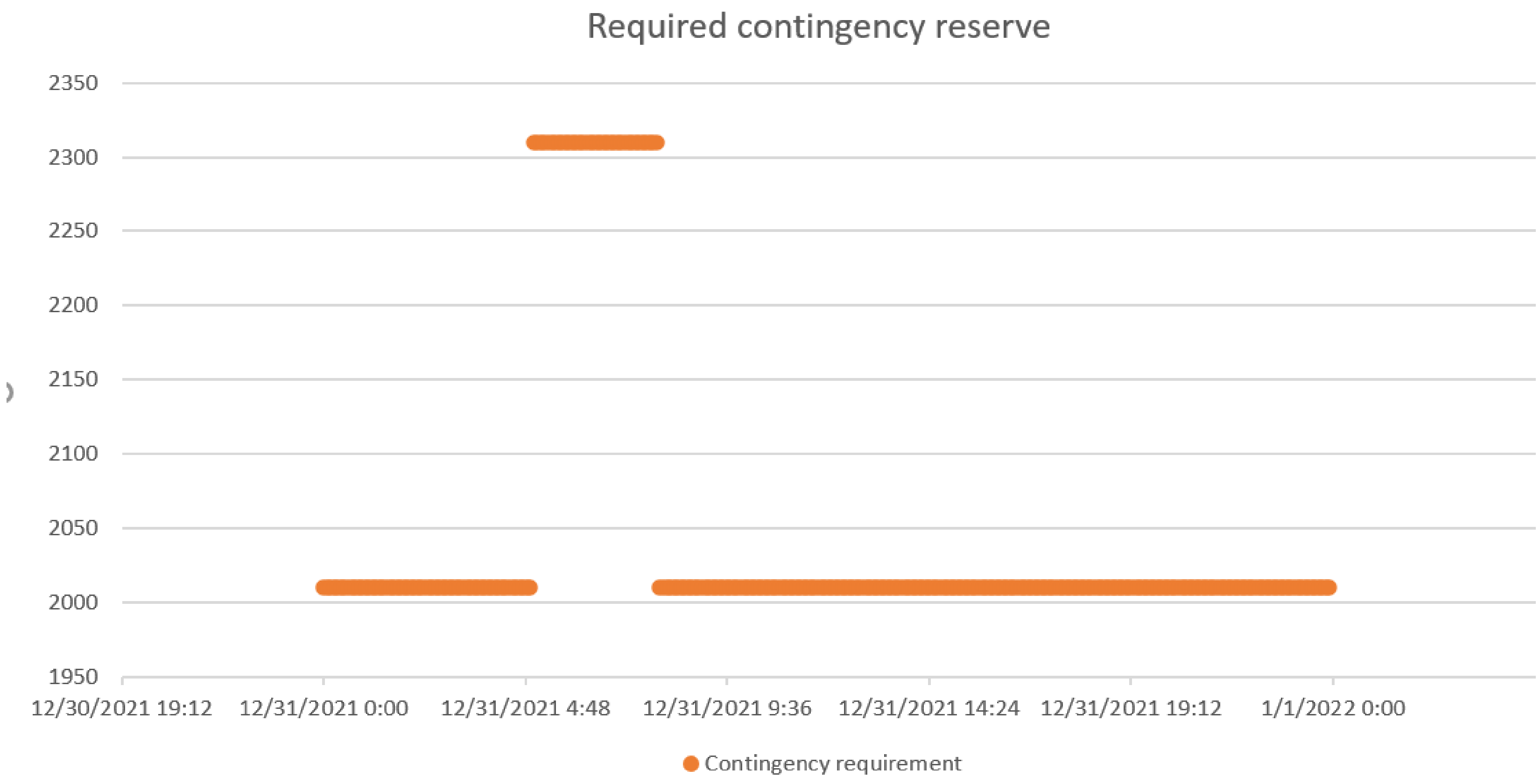
1. Range between (300 MW, 500 MW)
2. Based on time of day. (blue one below)
3. MISO doesn't have regulation up or regulation down. There is only one type, called regulation reserve.



The required contingency reserve

1. Spinning reserve: (need to be online, 10 min response time)
   - Around 900 MW during non-ramping hours
   - Around 1200 MW during ramping hours
2. Supplement reserve: 1100 MW (could be offline, 10 min response time)

So the sum of them always jump back and forth between 2000 MW and 2300 MW.



The required ramping capability (10min response time, should be online)

1. Variability component
2. Uncertainty component
   - Uncertainty up: 1075 MW
   - Uncertainty down: 575 MW

Ramping capability is called by Uds (unit dispatch system) automatically. It is like not decelerating since you know red light will turn to green when you reach there. If you make decisions solely by current situation (red light), when you really reach there, it would not be efficient, since you will spend more time. Besides, adding ramping capability won't make system unbalance, since this decision is made by looking ahead 30 min-60 min away and preposition in advance as preparation and net load will go with implementation together.

Eg: when Uds call ramp capability to ramp up, the system net load will also increase, since the later action has already been foreseen in advance.

$$RCup_t = \max([NetDemand_{t+n} - NetDemand_t] + Uncertainty_{up_{t+n}}, 0)$$

$$RCdn_t = \max([NetDemand_t - NetDemand_{t+n}] + Uncertainty_{dn_{t+n}}, 0)$$

48357	RTLMP_25-FEB-2022 15:50	2/25/2022 20:50	2/25/2022 15:50	985.70	664	1650.00
48358	RTLMP_25-FEB-2022 15:55	2/25/2022 20:55	2/25/2022 15:55	1144.60	506	1650.10
48359	RTLMP_25-FEB-2022 16:00	2/25/2022 21:00	2/25/2022 16:00	1211.40	439	1650.10
48360	RTLMP_25-FEB-2022 16:05	2/25/2022 21:05	2/25/2022 16:05	1109.30	541	1650.10
48361	RTLMP_25-FEB-2022 16:10	2/25/2022 21:10	2/25/2022 16:10	1143.30	507	1650.00
48362	RTLMP_25-FEB-2022 16:15	2/25/2022 21:15	2/25/2022 16:15	1176.90	473	1650.10
48363	RTLMP_25-FEB-2022 16:15	2/25/2022 21:15	2/25/2022 16:15	1176.90	473	1650.10
48364	RTLMP_25-FEB-2022 16:20	2/25/2022 21:20	2/25/2022 16:20	1186.50	464	1650.00
48365	RTLMP_25-FEB-2022 16:25	2/25/2022 21:25	2/25/2022 16:25	1162.80	487	1650.00
48366	RTLMP_25-FEB-2022 16:30	2/25/2022 21:30	2/25/2022 16:30	1225.20	425	1650.00
48367	RTLMP_25-FEB-2022 16:35	2/25/2022 21:35	2/25/2022 16:35	1168.50	482	1650.00
48368	RTLMP_25-FEB-2022 16:40	2/25/2022 21:40	2/25/2022 16:40	1088.30	562	1650.10
48369	RTLMP_25-FEB-2022 16:45	2/25/2022 21:45	2/25/2022 16:45	1167.50	483	1650.00
48370	RTLMP_25-FEB-2022 16:50	2/25/2022 21:50	2/25/2022 16:50	1611.70	38	1650.10
48371	RTLMP_25-FEB-2022 16:55	2/25/2022 21:55	2/25/2022 16:55	2014.20	1	2015.20
48372	RTLMP_25-FEB-2022 17:00	2/25/2022 22:00	2/25/2022 17:00	1705.00	1	1706.00
48373	RTLMP_25-FEB-2022 17:05	2/25/2022 22:05	2/25/2022 17:05	1409.70	240	1650.10
48374	RTLMP_25-FEB-2022 17:10	2/25/2022 22:10	2/25/2022 17:10	1433.20	217	1650.00
48375	RTLMP_25-FEB-2022 17:15	2/25/2022 22:15	2/25/2022 17:15	1436.80	213	1650.10
48376	RTLMP_25-FEB-2022 17:15	2/25/2022 22:15	2/25/2022 17:15	1436.80	213	1650.10

According to historical record shared by Yonghong, except those two periods, which have required ramp down reserve as 0 (they write as 1 for some Unknown reason), the rest ones are all around 1650 , which is 1075+575, so I think the rule is real.

Personally speaking, I feel uncertainty should represent unexpected change of net load (eg: an unexpected strong windy day) and variability should represent random variation part, but this is only a word issue. These two words can be found in reference below.[1]

[1] Ela, Erik, Michael Milligan, and Brendan Kirby. *Operating reserves and variable generation*. No. NREL/TP-5500-51978. National Renewable Energy Lab.(NREL), Golden, CO (United States), 2011.

The required STR (short term reserve)
(30 min response time, could be offline)

According to my discussion with Yonghong and Mike Carrion. This is created because MISO needs to "manage the contractual obligation to restore flows on the Regional Directional Transfer (RDT) constraint under agreed limits within 30 minutes". In other words, the required response time is 30 min, instead of 10 min in ramping reserve, so they can get more suitable units involved.

MISO's comment: For STR, I have derived seasonal and hourly requirement based on historical uncertainty distribution (net load + GenOU/derate -RT commitment).

According to our discussion during a virtual meeting, I think what she did was drawing that distribution based on lots of Monte carlo Simulations. Via the distribution and their typical net load, Gen derating/outage and other information, they got four typical hourly profile within one day. Each of them corresponds to one season.
These four profiles will be updated every year.

Q1. Which types of units can participate in ancillary service?

```
Unit Type
Battery Storage              76
CC                          560
CT Gas                     1310
CT Oil                      284
CT Other                     14
CT Renewable                 21
Conventional Hydro          332
External Transaction         17
Geothermal                    9
IC Gas                       84
IC Oil                       64
IC Renewable                 30
IGCC                          2
Industrial Loads              4
Interruptible Loads          93
Multiparty Transactions       1
Nuclear                      75
PV + BATT                   296
Pumped Storage Hydro         21
ST Coal                     430
ST Gas                      124
ST Oil                        7
ST Other                     19
ST Renewable                 93
Solar PV                   1010
Wind                        833
Name: Unit Type, dtype: int64
```

Resource	Day-Ahead and Real-Time			
	Regulating Reserve	Spinning Reserve	Supplemental Reserve	Ramp Capability
Committed or on-line Generation Resources	✓	✓	✓	✓
Committed or on-line Generation Resources with Fixed Dynamic Schedule	✓*	✓*	✓*	✓*
Committed or on-line Demand Response Resources - Type II	✓	✓	✓	✓
Available External Asynchronous Resources	✓	✓	✓	✓
Available Stored Energy Resources	✓			
Available off-line or uncommitted Quick-Start Resources			✓	
Uncommitted Demand Response Resources - Type I		✓	✓	

* For a synchronized Generation Resource associated with a Fixed Dynamic Schedule to remain eligible, it must maintain an Hourly Economic Minimum Limit equal to or greater than the Dynamic Interchange Schedule cap limit associated with the resource and an Hourly Economic Maximum Limit greater than the Hourly Economic Minimum Limit.

CT or IC

CT: combustion turbine. (might be able to participate in all types of reserves). CT-renewable: waste?
ST: steam turbine. spinning reserve&supplemental, not for regulation, since not fast enough.
IC internal combustion engine: all types
Batt: all four types
Pump hydro: mostly only for peak-shaving, probably regulation reserve a little, but contingency reserve is too much
Pv+batt:

Energy efficiency: not participate in market, just reduce load directly.
Interruptible load & industrial load: DR type II?
CC:
Transaction:

Energy & Operating Reserves Markets

Demand Response Resource (DRR) refers to a resource type: one that provides service to the energy and ancillary services market.

- **Demand Response Resource (DRR)-Type I:**
  - Resource owned by a single Load Serving Entity, or an ARC within the MISO BAA and that (i) is registered to participate in the Energy and Operating Reserve Markets, (ii) that is capable of supplying a specific quantity of Energy, Contingency Reserve or Capacity … through Behind the Meter Generation and/or controllable Load, (iii) is capable of complying with the Transmission Provider's instructions, and (iv) has the appropriate metering equipment installed.
- **Demand Response Resource (DRR)-Type II:**
  - Resource owned by a single Load Serving Entity, or an ARC within the MISO BAA and that (i) is registered to participate in the Energy and Operating Reserve Markets, (ii) is capable of supplying a range of Energy, Operating Reserve, Up Ramp Capability and/or Down Ramp Capability...through Behind-The-Meter generation and/or controllable Load, (iii) is capable of complying with Transmission Provider's Setpoint Instructions and (iv) has the appropriate metering equipment installed.

4. Transmission investment

1. Transmission Line (AC, DC): we just use retrofitting row of exploratory cost table.
   For AC lines, 69, 115, 138, 161, 230 kV we use rebuild cost, while for 345, 500 and 765kV, we use reconductor cost.
2. Transformer: ($/MW of each level transformer investment)

* 1.66 to include contingency cost and AFUDC.

AC

Location-State	69kV line	115kV line	138kV line	161kV line	230kV line	345kV line	500kV line	765kV line
investment cost	1.85	2	1.7	1.7	1.8	0.59	0.79	1.09
Power rating (MVA)	140	329	394	460	657	1792	2598	6625
investment cost per MW ($/MW/mil	13214.286	6079.0274	4314.7208	3695.6522	2739.726	329.24107	304.08006	164.5283

DC

Location-State	250kV line	400kV line	500kV line	600kV line	640kV line
investment cost	2.2533333	2.62	2.7733333	2.98	5.3866667
Power rating	500	1500	2000	2400	6000
investment cost per MW	4506.6667	1746.6667	1386.6667	1241.6667	897.77778

Transformer

Voltage class	69kV	115kV	138kV	161kV	230kV	345kV	500kV	765kV
69kV	5339	4346	4810	5063	5615	6895	8891	12510
115kV	4346	5913	4810	5063	5615	6553	8042	10292
138kV	4810	4810	6553	5339	5615	6553	8042	10292
161kV	5063	5063	5339	7259	5913	6895	8461	10292
230kV	5615	5615	5615	5913	8042	6895	8461	10292
345kV	6895	6553	6553	6895	6895	9796	8891	10800
500kV	8891	8042	8042	8461	8461	8891	13128	11914
765kV	12510	10292	10292	10292	10292	10800	11914	17595

How to know the line length of AC and DC?

Define DG=geodistance and DR=distanced based on reactance.
If 1.5*DG>DR>DG, use DR, else, use DG.

Ideas supporting the above are:
1.Distance must be at least DG.
2.But line will not route as straight line between two terminals and do distance should be greater
3.But distance should not be greater than 1.5 DG and if it is, something is strange with that reacta

Assumption: retrofitting process doesn’t need additional substation positions.

1. Phase shifter costs can be obtained from the xfmr exploratory table.
2. Three reactive compensation investment costs are got from chatgpt.
3. Branches whose kV levels are below 69 kV or non-MISO branches are ignored from investment.
4. However, while evaluating investment cost for equivalent branches, high voltage non-MISO branches will be considered. It is like when we inject 1 more MW flow at the two terminal buses of an equivalent branch near the MISO, the additional flow on Non-MISO branches will need additional capacities, as well as additional costs.

Sure, here's a rough estimate of the typical investment cost for reactive compensation components based on different voltage levels:

- For low voltage systems (e.g., 69 kV, 115 kV), the cost can range from $1,000 to $5,000 per MW.
- For medium voltage systems (e.g., 138 kV, 161 kV), the cost can range from $5,000 to $15,000 per MW.
- For high voltage systems (e.g., 230 kV, 345 kV, 500 kV, 765 kV), the cost can range from $10,000 to $30,000 per MW.

These are just approximate figures and actual costs may vary depending on factors such as technology, project requirements, geographical location, and market conditions. It's advisable to consult with relevant experts or suppliers for more accurate cost estimates tailored to your specific situation.

5. DSM

All existing DGPV and DR (interruptible load) have been removed, since their impact have been considered using MISO’s dataset.

DSM (Since DSM units are only included in the EGEAS file and not in the PROMOD file, except Interruptible load. I can only add DSM as new units.)

1. How MISO did:
   - Get expansion forecast from AEG
   - Use DSMlink to decide how much should be accepted. Note, this is a do-or-nothing decision.
   - And then distribute the accepted amount onto different buses based on engineers' experience, similar with other gens.
   - Implement transmission expansion.

2. How I did: should I treat it as a whole or multiple units? (Only let DR work at peak load. Put EE at all buses. Put DG as negative load forecast.)

   1. EE: reduce power consumption with advanced technology.
   2. DG: DG PV and DG thermal. Since DGPV's investment cost is much higher than utility PV, optimization won't select it by itself. However, DGPV amount will still increase due to incentive policy, people's wish for energy reliability and independence, so we treat it as negative load and use forecast data to represent its impact. This level of installation is at the distribution level.
   3. DR:
      Demand Response was sited at top load buses per LBA. Stakeholders had the opportunity to review and provide feedback on the buses identified. Alternative buses provided by stakeholder feedback were utilized in lieu of top load bus previously selected.
      Its main usage include:
      - filling valley – encourage more power consumption at valley period and integrate more renewable energy into grid.
      - shaving peak -- help reducing peak units' expense.
      - Providing ancillary service – frequency regulation and contingency reserve.

Since existing demand response in E2E has similar total capacity with the interruptible load, around 9000 MW.

We use interruptible load to represent demand response in dataset.

DER Type	EGEAS Program Block	DER Program(s) Included
DR	C&I Demand Response*	Curtailable & Interruptible, Other DR, Wholesale Curtailable
DR	C&I Price Response*	C&I Price Response
DR	Residential Direct Load Control*	Res. Direct Load Control
DR	Residential Price Response*	Res. Price Response
EE	C&I High-Cost EE*	Customer Incentive High, New Construction High
EE	C&I Low-Cost EE*	Customer Incentive Low, Lighting Low, New Construction Low, Prescriptive Rebate Low, Retro commissioning Low
EE	C&I Mid-Cost EE*	Customer Incentive Mid, Lighting Mid, New Construction Mid, Prescriptive Rebate Mid, Retro commissioning Mid
EE	Residential High-Cost EE*	Appliance Incentives High, Appliance Recycling, Low Income, Multifamily High, New Construction High, School Kits, Whole Home Audit High
EE	Residential Low-Cost EE*	Appliance Incentives Low, Behavioral Programs, Lighting, Multifamily Low, New Construction Low, Whole Home Audit Low
DG	C&I Customer Solar PV	C&I Customer Solar PV
DG	C&I Utility Incentive Distributed Generation	Combined Heat and Power, Community-Based DG, Customer Wind Turbine, Thermal Storage, Utility Incentive Battery Storage
DG	C&I Utility Incentive Solar PV*	C&I Utility Incentive Solar PV
DG	Residential Customer Solar PV	Res. Customer Solar PV
DG	Residential Utility Incentive Distributed Generation	Customer Wind Turbines, Electric Vehicle Charging, Thermal Storage, Utility Incentive Battery Storage
DG	Residential Utility Incentive Solar PV	Res. Utility Incentive Solar PV

Table 5: EGEAS Program Block/Specific DER Program Mapping

1. Get DSMLink selected capacity forecast and then distribute them onto all load buses based on load ratio, since DSM is essentially used to reduce load burden.
2. Allow all DR to work only at peak moment. Egeas uses total energy consumption to achieve this. We used a simple way to approximate this while maintaining low computational burden.
3. Take capacity factors into consideration.
4. EE and DGPV will always work.
5. All DSM programs will be treated as parameters, similar as negative forecasted load. The difference is DR will only work at Peak moment, while DGPV and EE will always work.
6. Don't consider ancillary service, or filling valley here.

We use DG and EE to offset load in operation. (capacity factors will be considered here.)
DR will only be used for peak shaving service, since its capacity factors are only around 0.01, which means they only work around few days a year, while one block time can be around 15-30 days.
Another thing is interruptible load in the generator model have been removed, since DSM files include multiple types of DR and I Think those existing ones have already been included in them.

Siting process rule

1. Universal siting criteria
   1. Only finding siting buses from 5-year and 10-year MTEP promod model. The difference should mainly be renewable capacity and integration time.
   2. 80% of renewable should be on existing interconnection buses, while remaining 20% on new places. General rule, but strictly fixed ratio.
   3. N-1 expansion capacity limit.
   4. Siting should be mainly on MISO buses, except requested by stakeholder.
   5. Each LRZ zone should be able to balance its gen and load roughly.
   6. Radial lines should not be allowed for integration.
2. Wind and solar PV

Wind and solar PV resources were modeled as aggregated systems that can be installed within 10-30 miles of each site. Renewable capacity was primarily allocated to meet local RPS goals at each milestone year (2027, 2032, 2037, 2042). The remaining capacity was then distributed with the following priorities:

1.80% to active high-priority GI sites, and if exceeded, to other lower-priority sites.

2.The remaining 20% was distributed based on the local GI queue capacity, favoring high-capacity buses and sites recommended by stakeholders.

The phrase "can be installed within 10-30 miles of each site" in the context of wind and solar PV resources means that these renewable energy systems are modeled as being capable of being deployed within a 10- to 30-mile radius from a designated site. Here's a more detailed breakdown of its meaning:

1.Aggregated Capacity Potential:

1. The phrase implies that the potential for installing wind or solar PV capacity is not limited to a single point but is spread over an area within a 10- to 30-mile range from a central site. This allows for flexibility in the exact locations where the installations can occur.

2.Collector System:

1. The concept of a "collector system" suggests that the energy generated by these distributed installations within the specified range will be collected and aggregated as if it were produced by a single, centralized system. This approach helps in optimizing the use of space and resources.

3.Flexibility in Siting:

1. By allowing installations within a 10- to 30-mile radius, there is flexibility to select specific locations that may have better wind or solar resources, more favorable land conditions, or fewer regulatory hurdles, while still being considered part of the same project or site.

4.Proximity to Infrastructure:

1. The specified range ensures that installations are close enough to existing infrastructure, such as substations or transmission lines, to facilitate the efficient integration of generated power into the grid.

5.Scale of Deployment:

1. It suggests a broader, more regional approach to deployment rather than a highly localized one. This can lead to more effective utilization of land and resources, especially in areas with variable renewable resource availability.

Overall, "within 10-30 miles of each site" means that the installations can be distributed over an area of up to 30 miles from a designated central point, offering greater flexibility and efficiency in the siting and deployment of renewable energy resources.

3. Utility-scale solar PV and storage

Hybrid units were sited in the same locations as Solar PV units. For the purpose of fulfilling Renewable Portfolio Standard (RPS) goals, only 80% of the generation from Hybrid units was considered as RPS-eligible. This adjustment was made to account for the differences in eligibility between the solar and battery components on an individual RPS basis.

4. DGPV （we don’t have dGen, so we cannot implement what MISO did.）

The siting methodology for Distributed Generation Solar PV (DGPV) utilized the National Renewable Energy Laboratory’s (NREL) Distributed Generation Market Demand Model (dGen) and involved the following steps:

•Identified the top 25 counties with the highest DGPV potential within each Local Resource Zone (LRZ) using the dGen model.

•Selected up to 30 major load buses for each county.

•Distributed the capacity across counties according to the weighting from dGen results.

•Capped DGPV sites at a maximum capacity of 25 MW within MISO and 50 MW for external pools, based on stakeholder feedback received during the Future 2A siting process.

5. Li-battery

Batteries were required to contribute a minimum cumulative capacity over MISO should be at least 50 MW by 2042 and were capped at a maximum cumulative capacity of 400 MW to ensure the effective performance of the PROMOD model.

1. **Primary Allocation (80% of Total Capacity)**:
    1. 80% of the total battery storage capacity was allocated to Active DPP Phase 1, 2, or 3 GI sites.
    2. If this 80% allocation exceeded the available capacity at these GI queue sites, the GI sites were utilized to their maximum capacity, and any remaining capacity was then distributed to lower-priority sites.
    3. GI projects were prioritized based on their status in the GI queue, with projects further along in the GI study process being ranked higher.
2. **Secondary Allocation (20% of Total Capacity)**:
    1. The remaining 20% of the total battery storage capacity was distributed among Local Resource Zones (LRZs) in proportion to each LRZ's share of the total GI queue capacity for battery resources. This distribution followed these guidelines:
        1. 80% of this remaining 20% capacity was allocated to identified top load buses with voltages greater than 100 kV.
        2. 20% of this remaining 20% capacity was allocated to the buses with the highest N-1 capacity near generation sources.
        3. If an LRZ needed more than one battery site, the next bus selected was from a different county to ensure a broader geographical distribution.

6. Demand response

Demand Response was sited at top load buses per LBA. Stakeholders had the opportunity to review and provide feedback on the buses identified. Alternative buses provided by stakeholder feedback were utilized in lieu of top load bus previously selected.

7. CC and CT

- Combined Cycle units were given precedence over Combustion Turbine units for higher priority sites.
- Priority 1: Sites in the Active Definitive Planning Phase (DPP) Phase 1, 2, or 3 of the Generator Interconnection Queue.

  The Active Definitive Planning Phase (DPP) Phase 1, 2, or 3 of the Generator Interconnection Queue refers to different stages in the process for connecting new generator projects to the electrical grid managed by entities like MISO (Midwest Independent System Operator). Here's a breakdown of what each phase typically entails:

  1. **Phase 1**: Preliminary Study
     1. In Phase 1, a generator developer submits a request to connect their project to the grid. This phase involves initial feasibility studies and assessments to determine if the project can be interconnected without major issues.
  2. **Phase 2**: System Impact Study (SIS)
     1. If a project advances past Phase 1, it enters Phase 2, where a System Impact Study (SIS) is conducted. This study evaluates the potential impacts of integrating the generator into the grid, including technical assessments of grid stability, reliability, and necessary upgrades.
  3. **Phase 3**: Definitive Planning Phase
     1. Phase 3 involves detailed planning and engineering work. It includes the development of a detailed interconnection agreement and specific plans for how the generator will connect to the grid. This phase also addresses any required system upgrades and finalizes the terms and conditions for interconnection.

  Active Definitive Planning Phase (DPP) indicates that a project is actively progressing through one of these phases (Phase 1, 2, or 3) of the Generator Interconnection Queue. Projects in these phases are considered to have a clearer path towards actual implementation, pending final approvals, agreements, and necessary infrastructure modifications. These phases are crucial for ensuring that new generator projects can connect to the grid efficiently while maintaining grid reliability and stability. The progression through these phases involves coordination between the generator developer, the grid operator (such as MISO), and potentially other stakeholders to ensure smooth integration into the electrical grid infrastructure.

- Priority 2: Brownfield sites, including existing sites and those that have been retired.
  - Retired sites were ranked based on their earliest commissioning date and had to have a capacity of 50 MW or greater.
- Priority 3.1: Sites in the SPA (System Impact Study) or Canceled/Postponed Generator Interconnection Queue.
- Priority 3.2: Greenfield sites, adhering to specific siting criteria.

In essence, this framework ensures that Combined Cycle units are prioritized at favorable locations compared to Combustion Turbine units. The prioritization within each category considers factors such as project phase, site readiness, and historical site usage, aiming to optimize the integration and efficiency of power generation facilities within the MISO grid.

8. Flexible units which are used for ancillary service

1. **Flexible Attribute Units**: These units refer to resources that possess flexible operational characteristics, such as the ability to adjust output quickly or provide ancillary services to support grid stability.
2. **Siting Priorities**:
    1. **Priority 1**: Retirement sites were chosen primarily to fulfill deficits in the Planning Reserve Margin Requirement (PRMR) at the Load Resource Zone (LRZ) level. This decision was made after allocating other types of resources. Sites within LRZs were ranked based on when they were originally commissioned (earliest first).
    2. **Priority 2**: After addressing the PRMR requirements, additional retirement sites were selected and utilized based on their earliest commissioning dates.
3. **Timing (Future 2A)**:
    1. The timing of placing Flexible Units was influenced by the aforementioned priorities. Most of the Flexible capacity was installed within Year 5 of the study period (specifically 2027). Some units were placed in later years due to either a shortage of available retirement sites with earlier commission dates or strategic selection based on PRMR needs.
4. **Scope and Selection Criteria**:
    1. Flexible Attribute Units were chosen not only based on their technical capabilities but also to represent a broad spectrum of existing and emerging technologies. These units were not restricted solely to thermal brownfield sites located within state and local balancing authorities that lacked specific clean energy goals.

Overall, this strategy aims to optimize the deployment of Flexible Attribute Units at retired brownfield sites to enhance grid reliability and flexibility, while considering both technical feasibility and broader energy policy objectives.

1. Python code is used to generate an ACEP_dataset, which serves as the base. It doesn’t include new units and it treats DR as gens.
2. Matlab function “build_original_case.m” will generate a real ACEP_dataset based on the above one. In this file, DSM will be Treated as negative load and selected types of new units will be added onto selected buses.
3. External ISO region will not allow gen expansion, nor load increase.