

A large, white lattice transmission tower stands against a clear blue sky. Power lines stretch across the frame from the tower. The bottom of the image features a decorative blue and white wavy graphic.

Transmission Expansion Advisory Committee Meeting

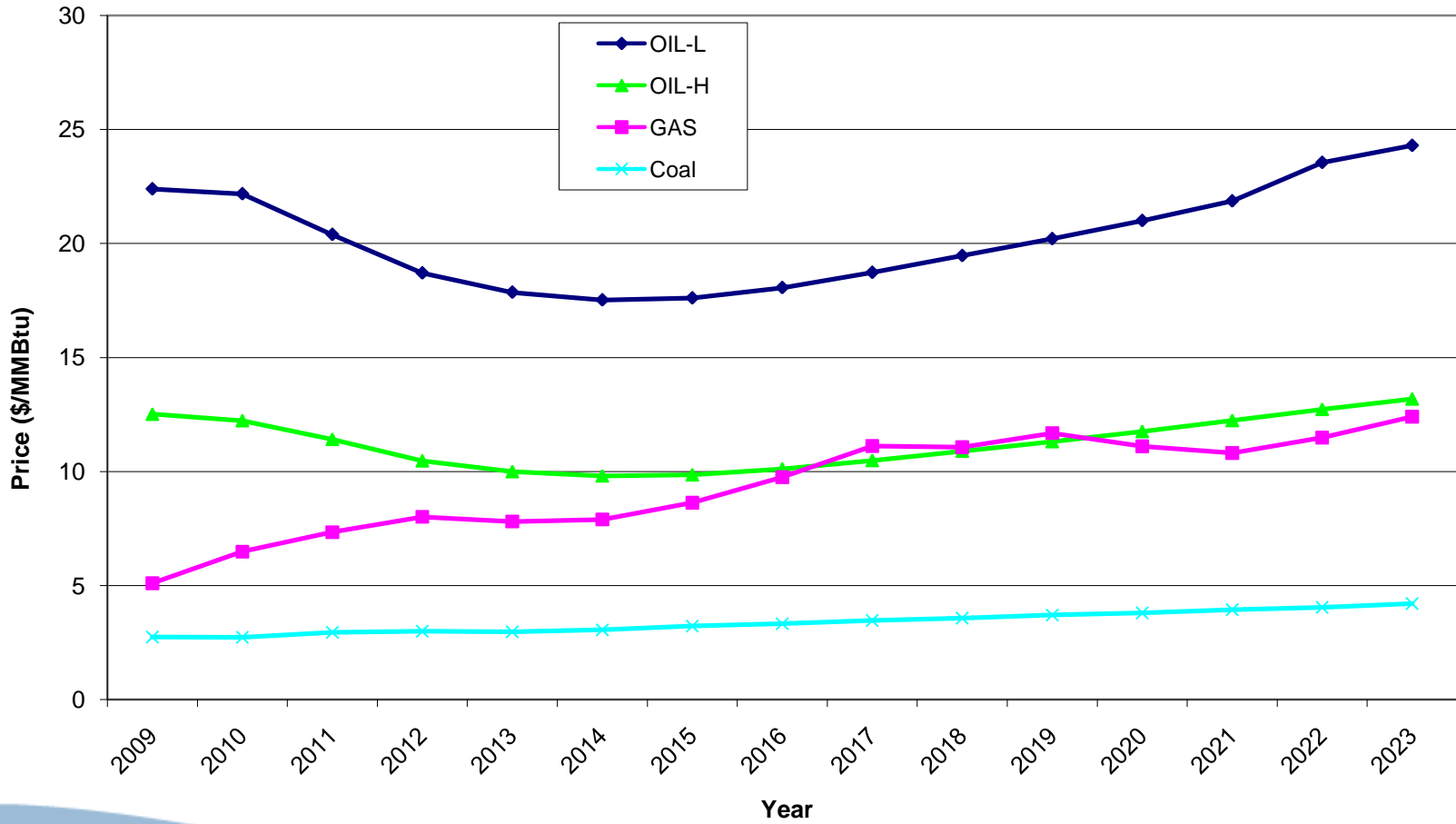
2009 Market Efficiency Analysis Input Assumptions

May 20, 2009

- Study years: 2009, 2012, 2015, 2018, 2023
- PROMOD IV model from Ventyx
- Underlying input data contained in PROMOD Powerbase (February 2009 update) including generating units and unit characteristics, fuel costs and emissions costs
- Powerflow Cases
 - 2009 power flow case to represent today's "as-is" system
 - 2013 RTEP power flow case to represent future system

- Fuel prices
- Load and energy
- Future generation scenario
- Emissions prices
- Transmission topology
- Carrying charge rate and discount rate

Figure 1 - Fuel Price Assumptions



- PJM zonal peak and zonal energy forecast from PJM 2009 Load Forecast Report
- Historical zonal hourly loads used to develop zonal hourly load shape

Table 1 – Forecast PJM Peak and Energy

	2009	2012	2015	2018	2023
Peak (MW)	134,428	144,613	151,410	156,822	165,006
Energy (GWh)	712,236	766,257	800,420	829,620	871,619

- Modeled demand response quantities based on RPM auction results
- 2009 study year values are sum of ILR Forecasted Planning Period Parameters and DR (cleared and FRR) from 2009/10 BRA
- Value for study year 2012 based on DR (cleared and FRR) from 2012/13 BRA

	2009	2012	2015	2018	2023
Demand Response (MW)	2,940	7,536	7,536	7,536	7,536

- generation model includes all existing in-service generation plus active queue generation with executed ISA minus expected future deactivations
- installed reserve requirement is met through 2013
- To meet installed reserve requirement for study years 2015, 2018 and 2023, 3,900 MW, 10,200 MW and 18,100 MW of new generation will be added to model, respectively
- New generation will be added to PJM regions in proportion to the regional location and regional generation type of future generation projects in Generation Interconnection Queues through Queue U

Figure 2 - PJM Market Efficiency Reserve Margin

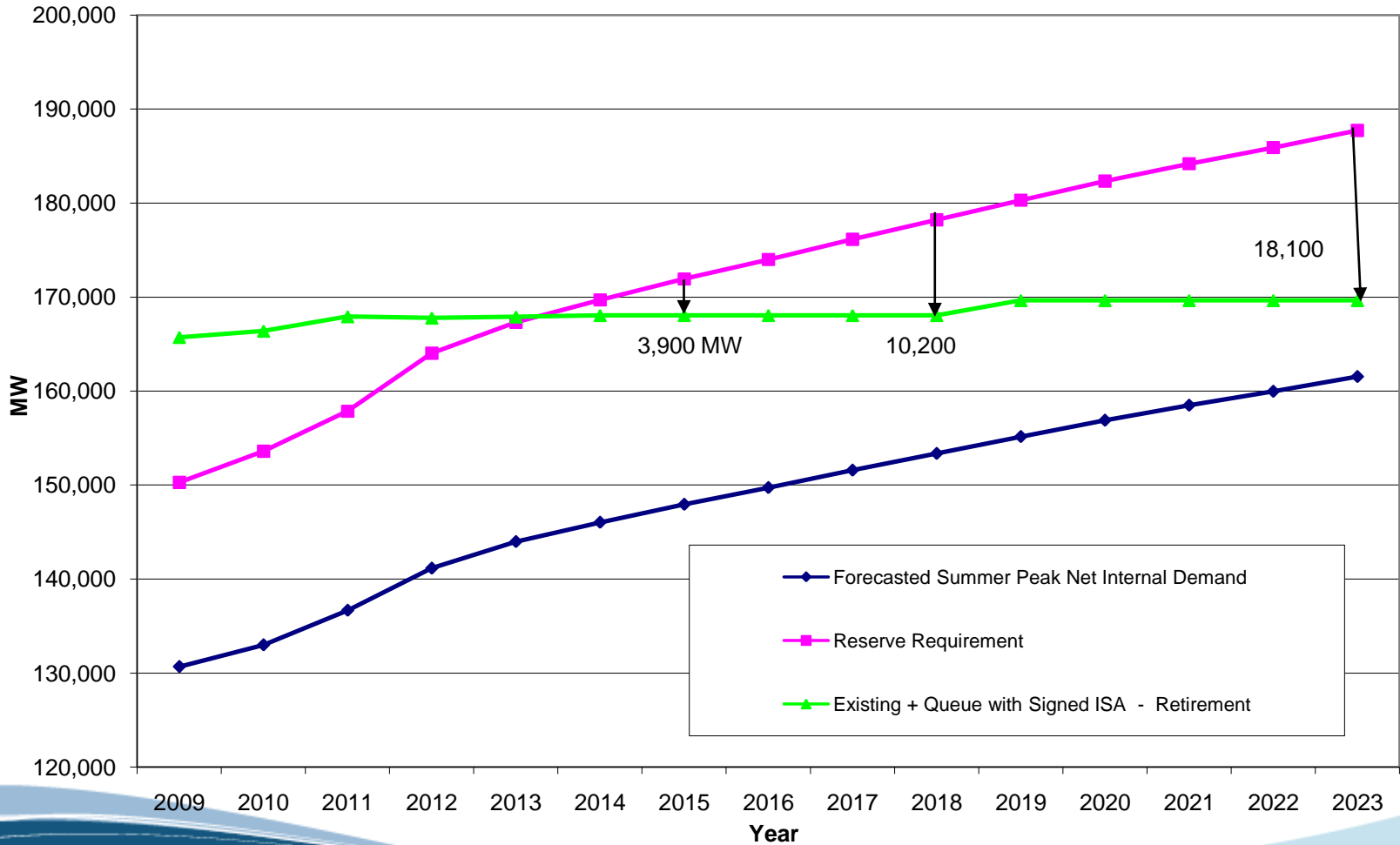


Table 2 – Location and Generator Type to Maintain Reserve Margin

Region	Nuclear	Coal	Gas	Oil	Wind	Other Renewable	Total Region
AECO/DPL/JCPL/PECO/PSEG	0.3%	0.0%	23.1%	0.6%	1.0%	2.3%	27.4%
AEP/APS/COM/DAY/DUQ	0.4%	10.6%	12.5%	0.0%	14.3%	1.0%	38.8%
BGE/PEP	3.6%	0.0%	4.0%	0.0%	0.0%	0.0%	7.6%
DOM	0.8%	0.0%	6.6%	0.0%	0.1%	0.6%	8.1%
ME/PN/PPL	3.5%	0.2%	10.7%	1.7%	1.2%	0.7%	18.1%

Figure 3 - SO2 Emission Allowance Price Assumptions

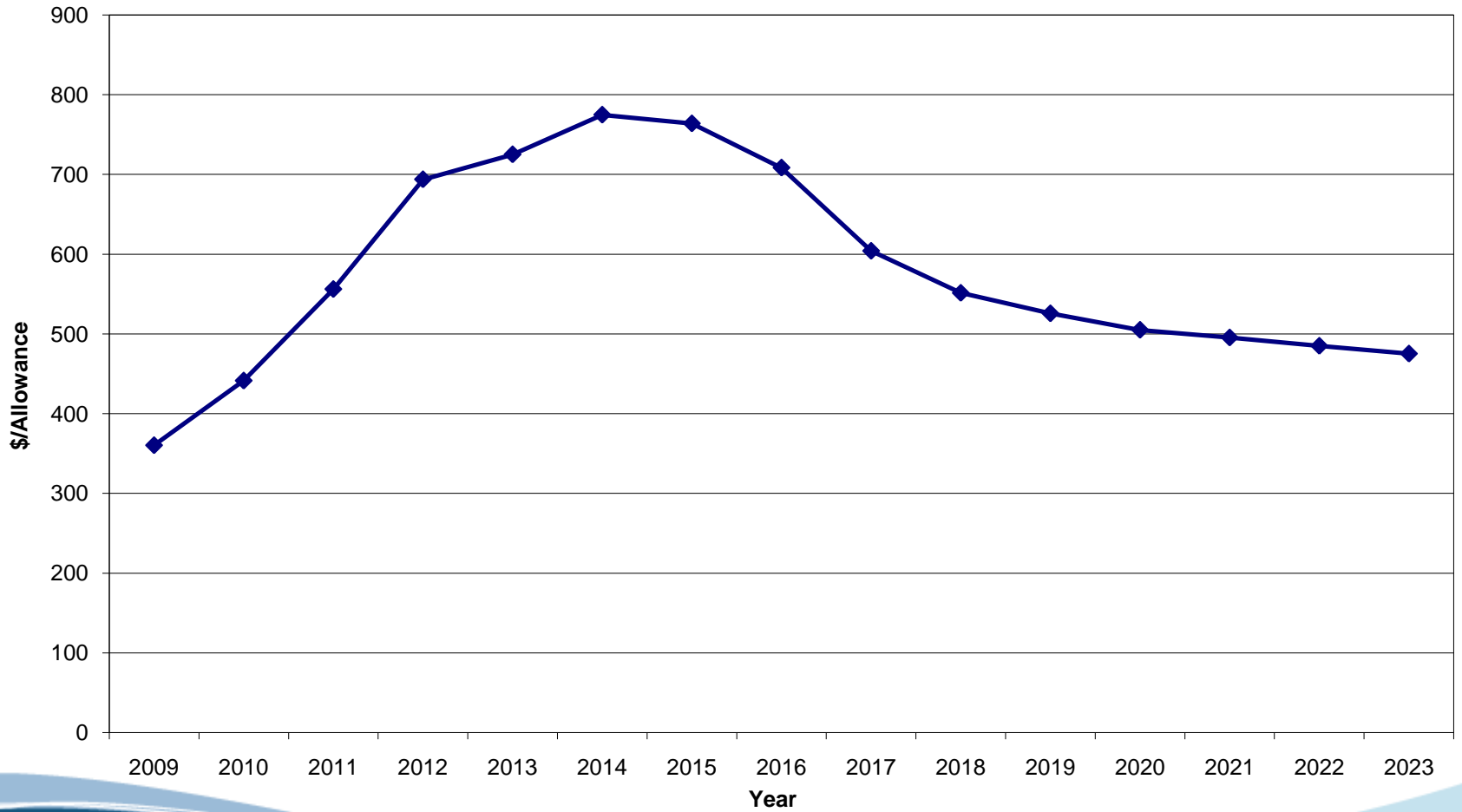


Figure 4 - NOx Emission Allowance Price Assumptions

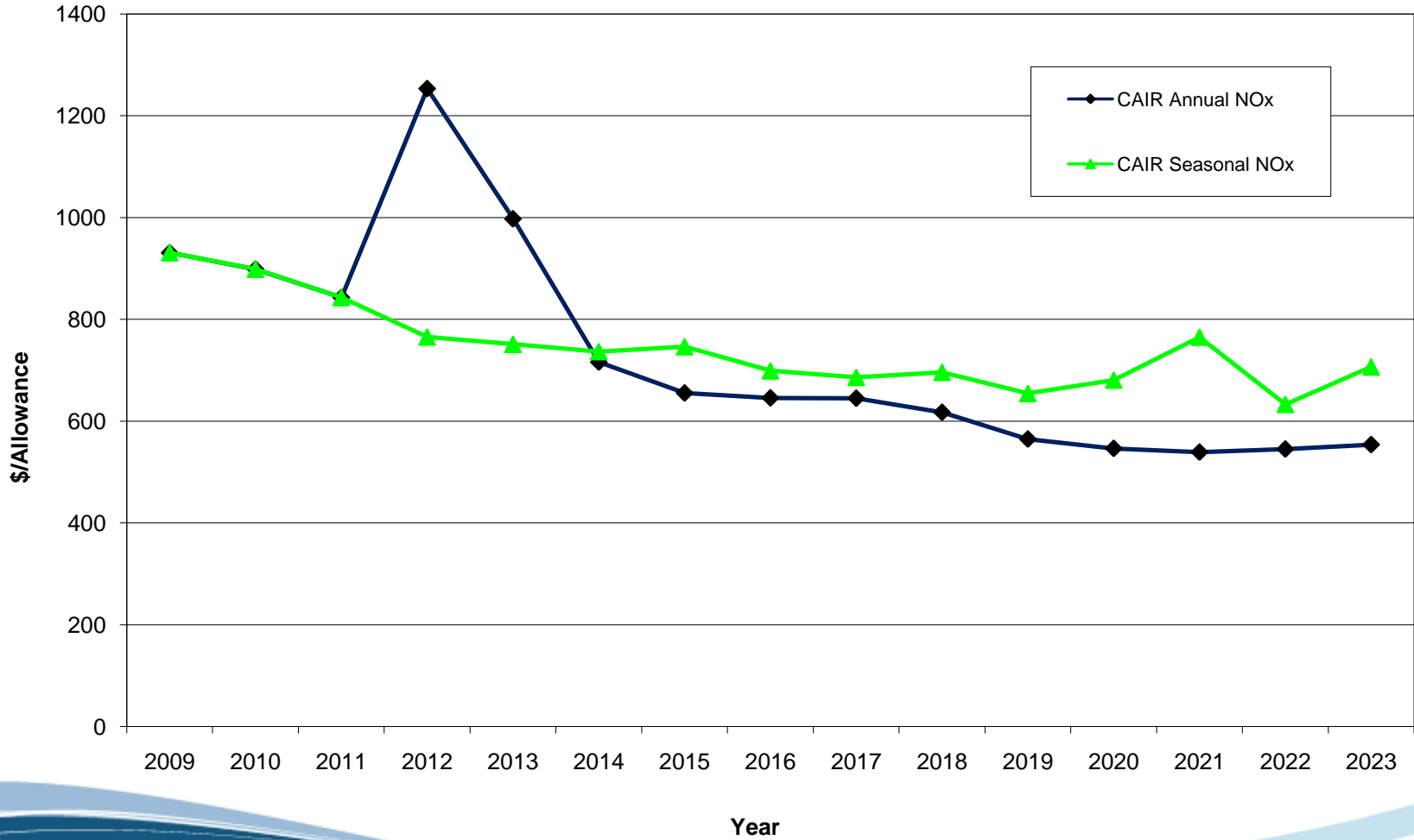
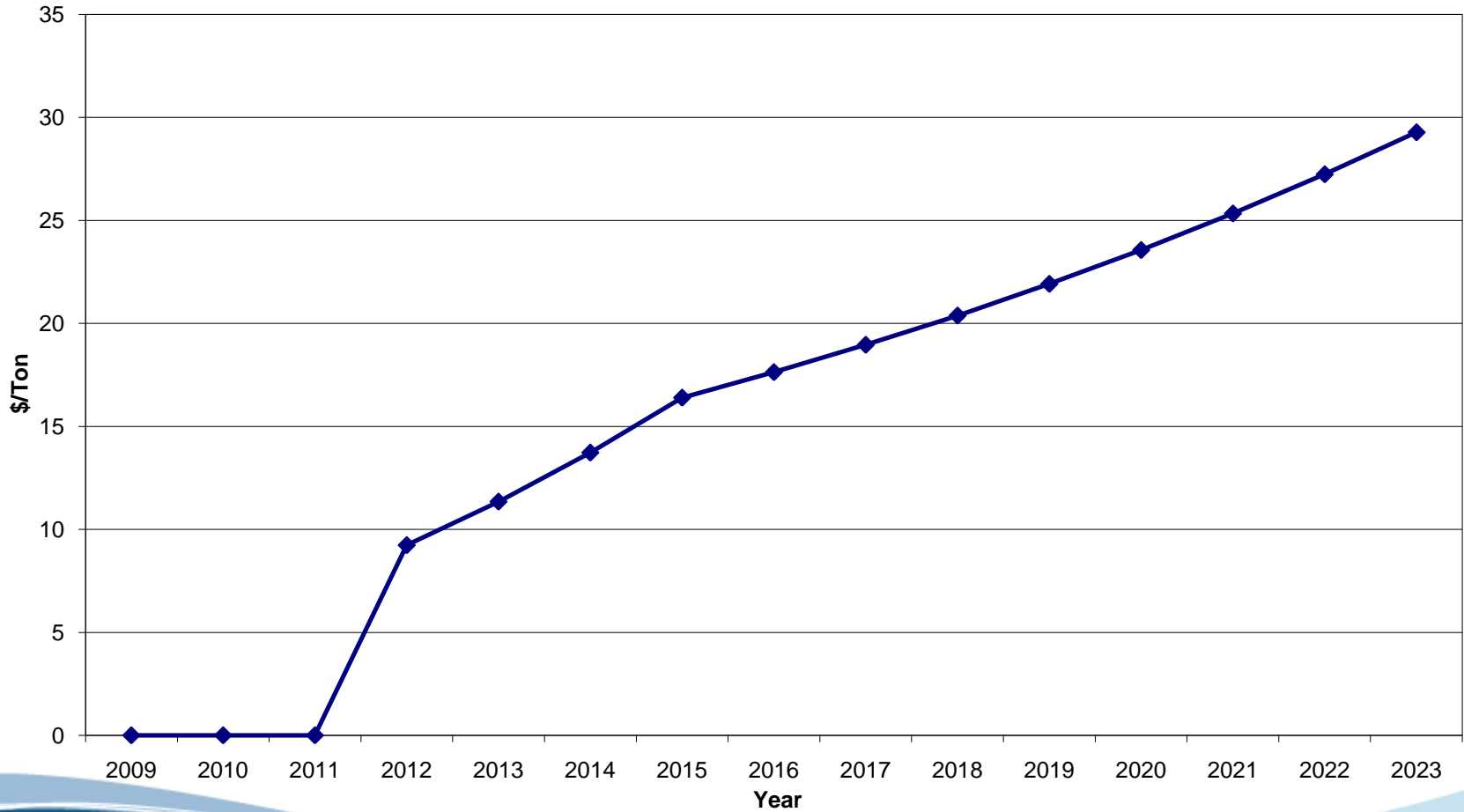


Figure 5 - CO2 Emission Assumptions



- Powerflow Cases
 - 2009 power flow case to represent today’s “as-is” system
 - 2013 RTEP power flow case to represent future system
- Thermal Constraints
 - monitor/contingency pairs
 - NERC Book of Flowgates
 - Planning study results
 - Historical PJM congestion events
 - monitor/contingency list for “as-is” case posted on PJM web site under “Planning - RTEP Development – Market Efficiency”
- Voltage Constraints
 - PJM reactive interface limits
 - MW limits based on historical values for “as-is” case adjusted for future upgrade impacts in 2012 case

- Discount rate and levelized carrying charge rate developed using information contained in TO Formula Rate sheets posted on PJM web site
- Discount rate based on weighted average after-tax embedded cost of capital (average weighted by TO total capitalization)

Discount rate = 7.73%

- Levelized annual carrying charge rate based on weighted average net plant carrying charge (average weighted by TO total capitalization) levelized over an assumed 45 year life of project

Levelized Annual Carrying Charge Rate = 19.8%

- PJM Board approval of input assumptions in June
- Begin analysis with regular updates to TEAC