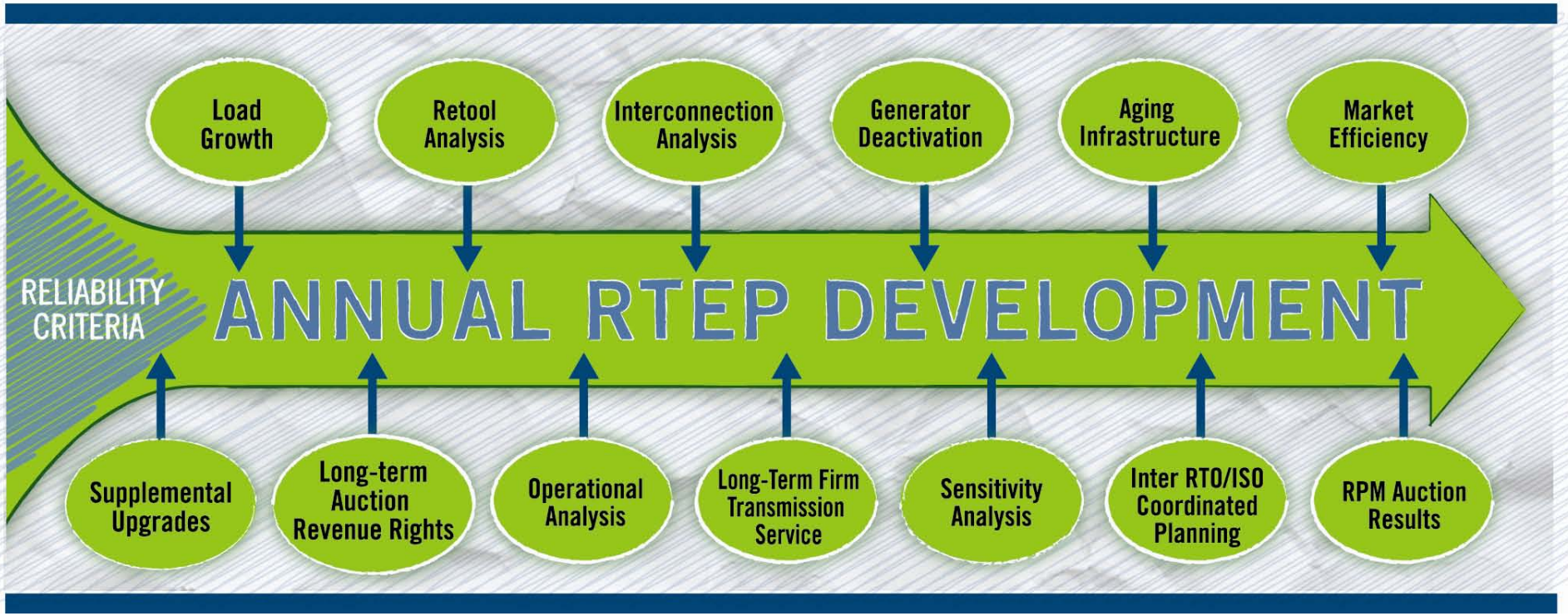
PJM Planning Process Strawman

RPPTF
April 11, 2011
Steve Herling

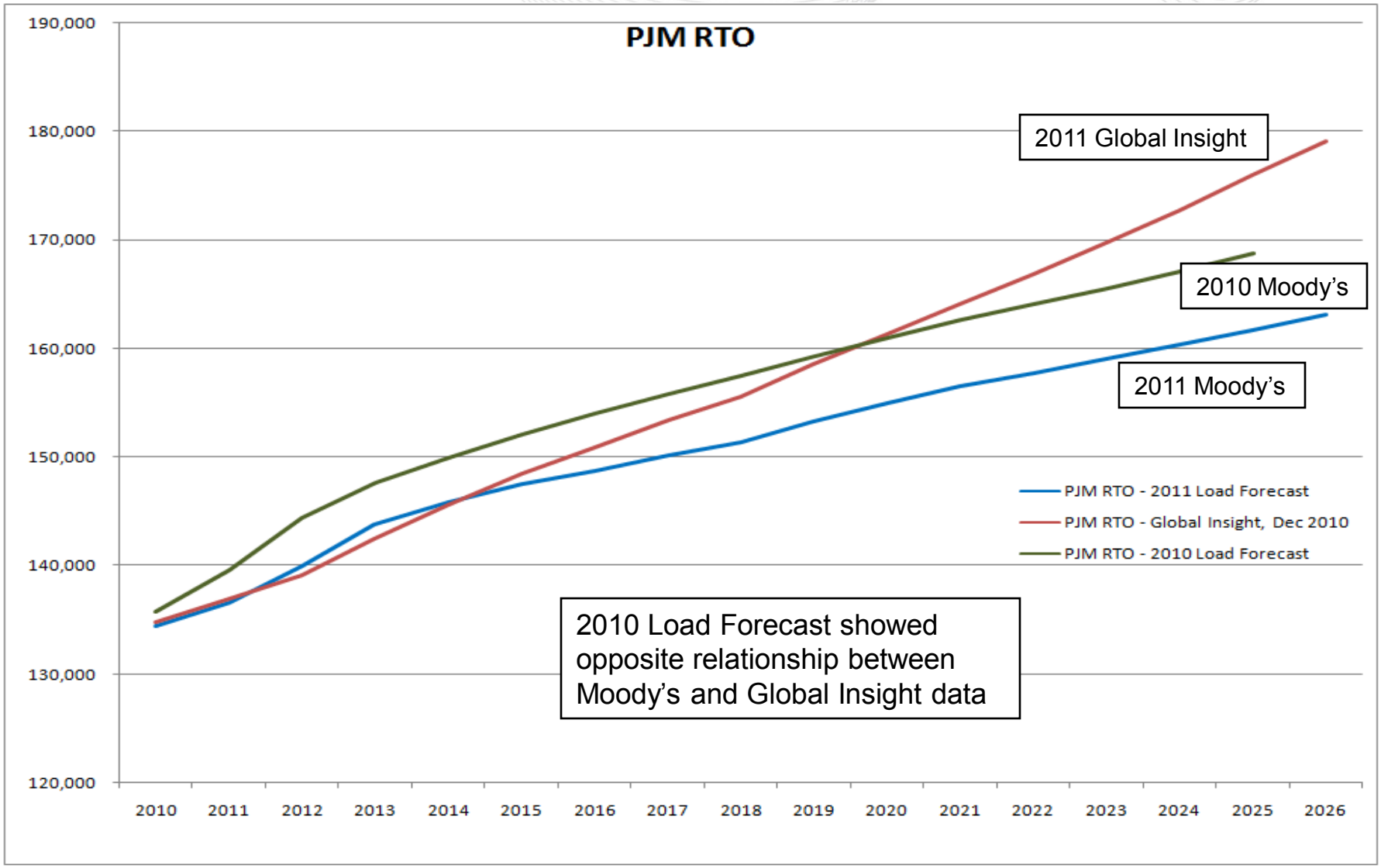
RTEP Development Drivers



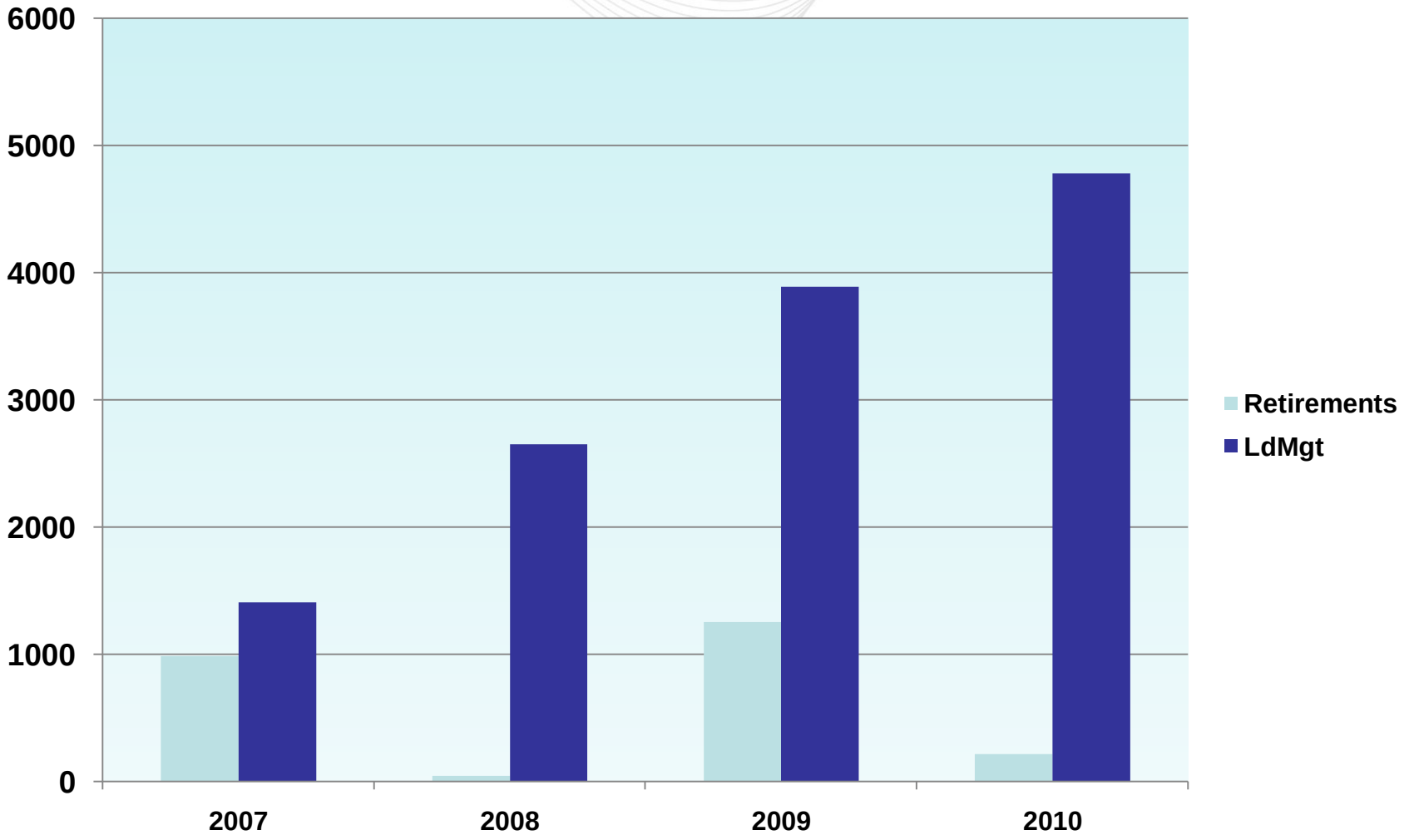
Areas of Uncertainty

- Load Forecast
  - Volatility of Economy
- Generation Mix
  - Retirement of At-Risk Generation
  - Future Renewable Generation Integration
    - Costs of off-shore generation versus long distance on-shore generation
  - Future of nuclear generation
  - Development of Marcellus Shale
- Impact of Uncertainties on Transmission Build-out
  - Delays/Suspension of major transmission projects
  - Uncertainty for generation development
  - Uncertainty for markets

Example – PJM RTO 2011 Load Forecasts



EMAAC/MAAC Retirements Announced and Load Management

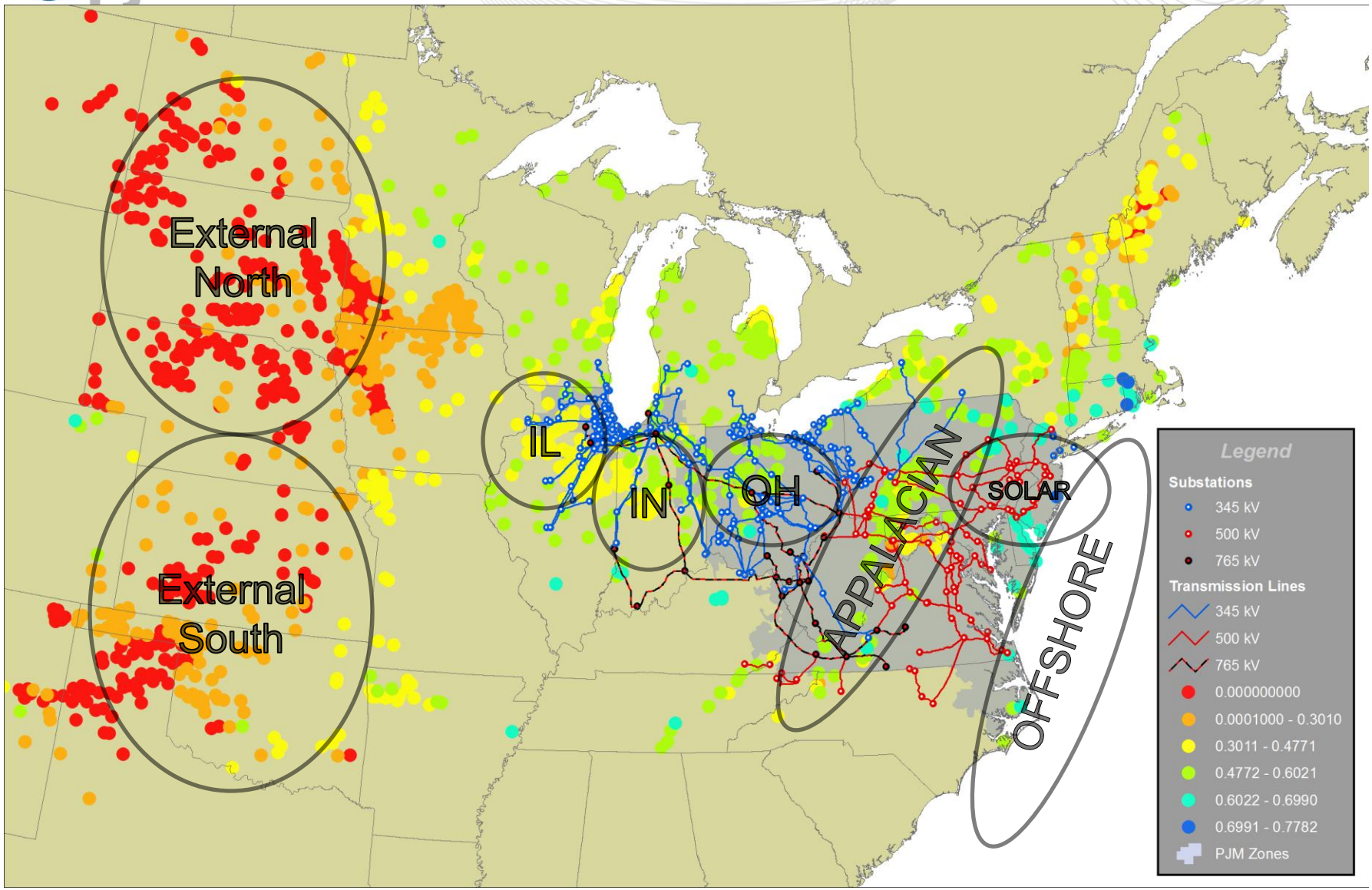


Composition of Capacity in PJM Employing Once Through Cooling

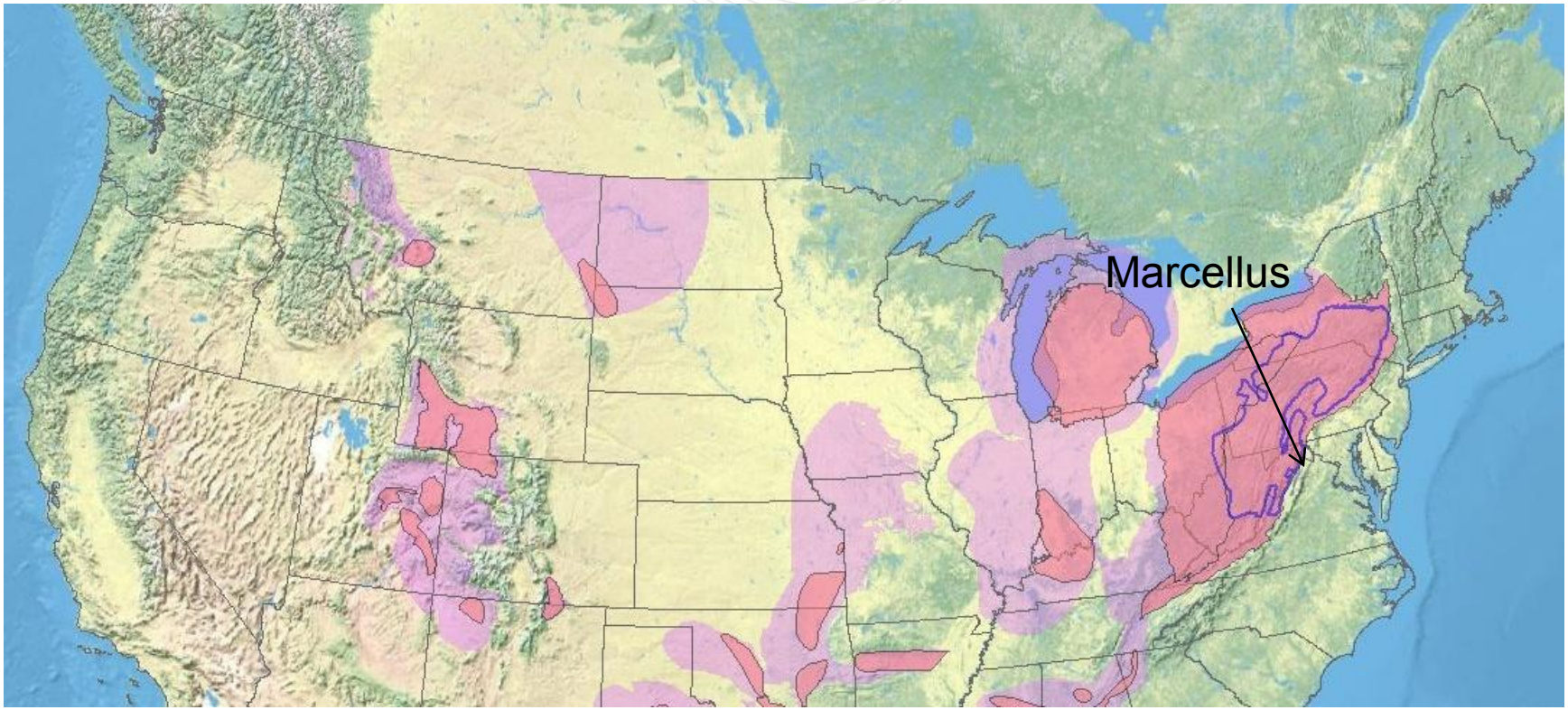
	PJM RTO	MAAC	Rest of PJM
Oil and Gas	4,271	3,070	1,201
Nuclear	11,930	4,658	7,271
Coal	28,167	9,498	18,669
Coal > 40 years	25,554	8,878	16,676
Coal < 400 MW	17,470	6,947	10,523
Coal > 40 years, < 400 MW	17,157	6,947	10,210

Source: PJM EIA-411 Submittal as of January 1, 2009 and EIA-767, 2000 and 2005, EIA-860, 2008
MW of Summer Net Dependable Capacity

Renewable Sourcing Zones

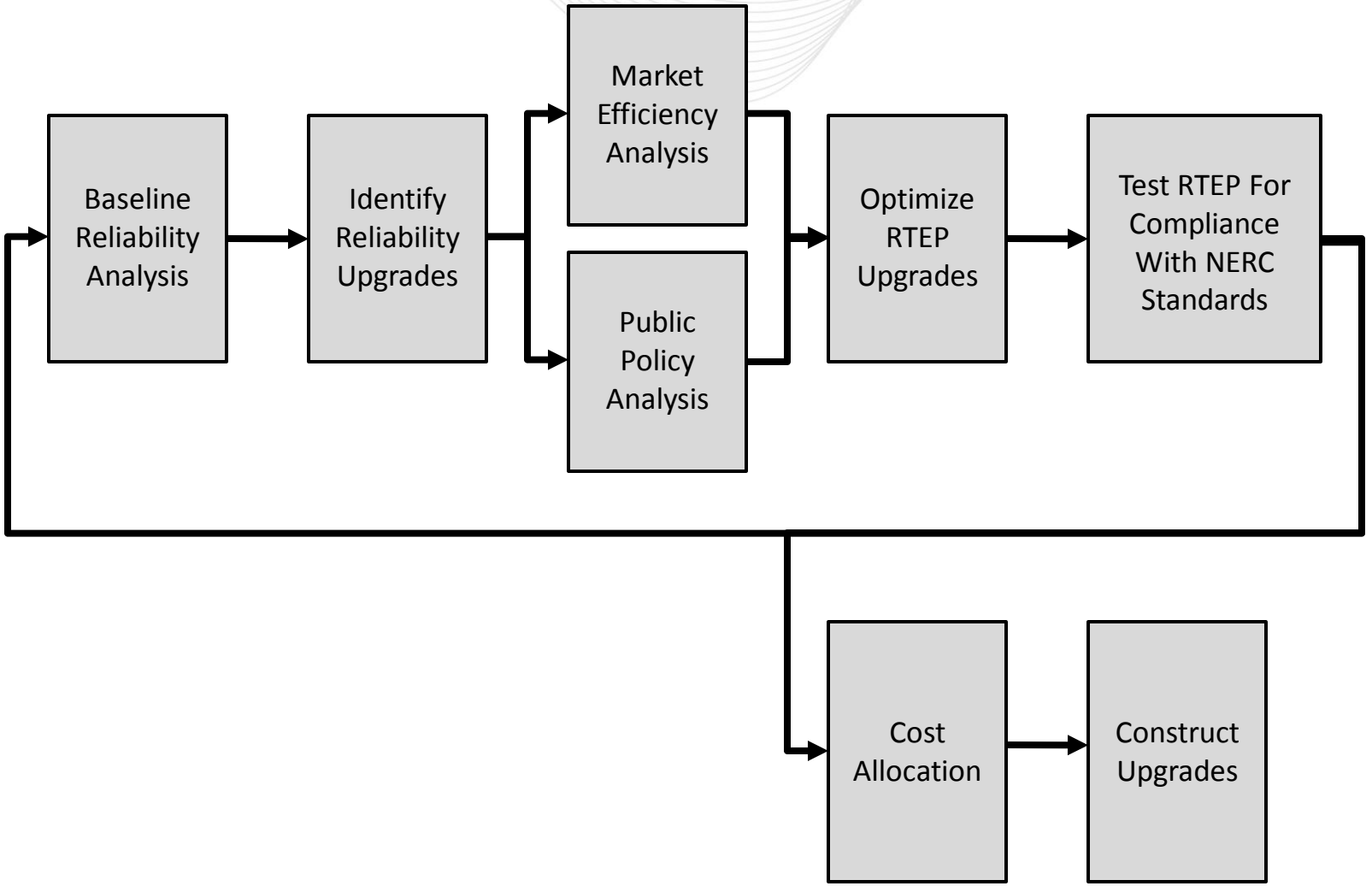


Marcellus Shale

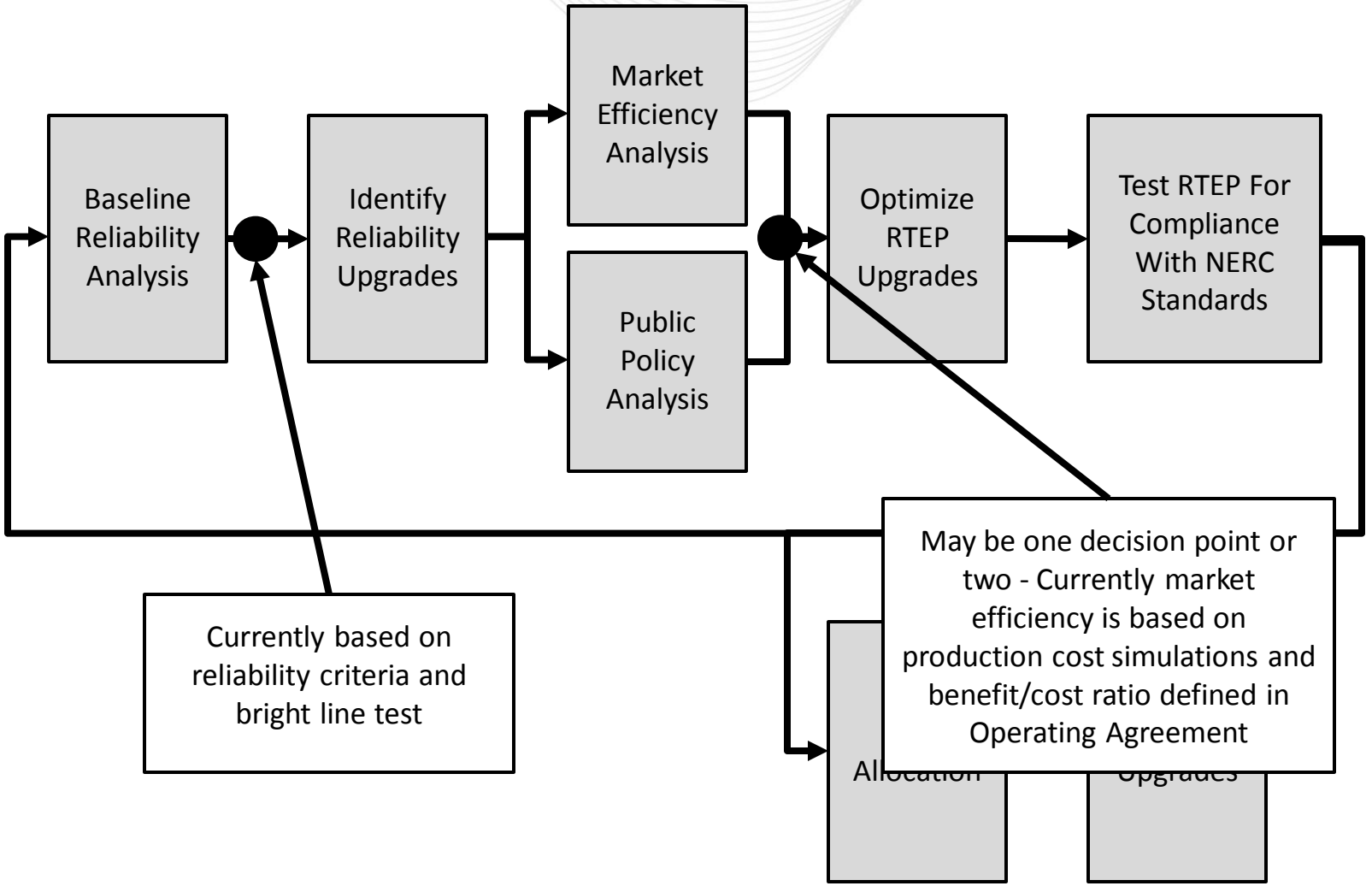


Source: Energy Information Administration based on data from various published studies.
Updated: March 10, 2010

General RTEP Framework

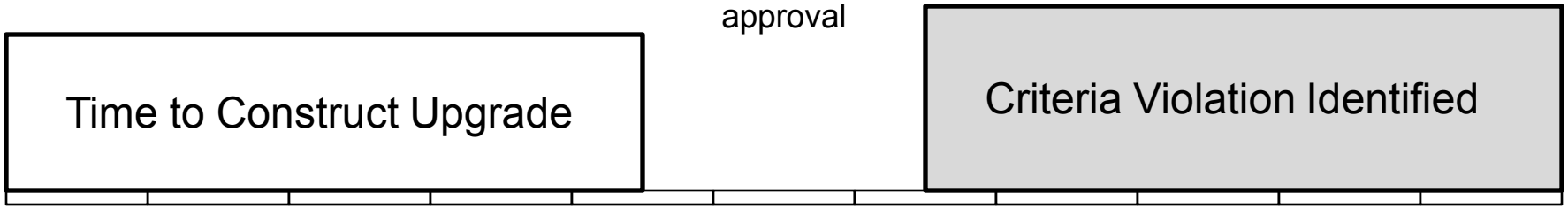


General RTEP Framework Decision Points

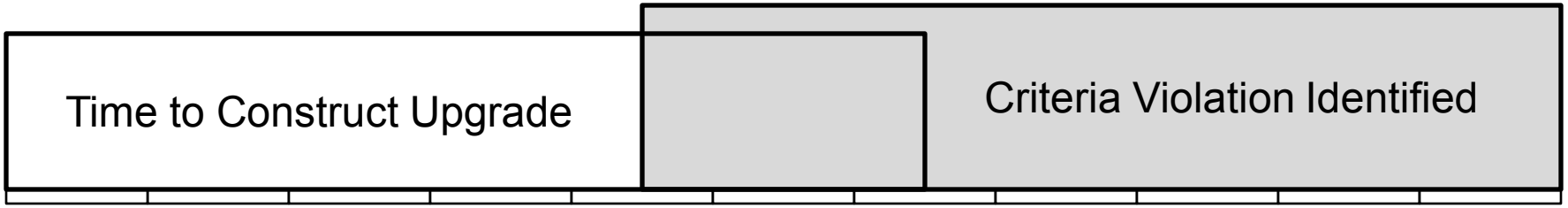


Existing Bright-Line Decision Framework

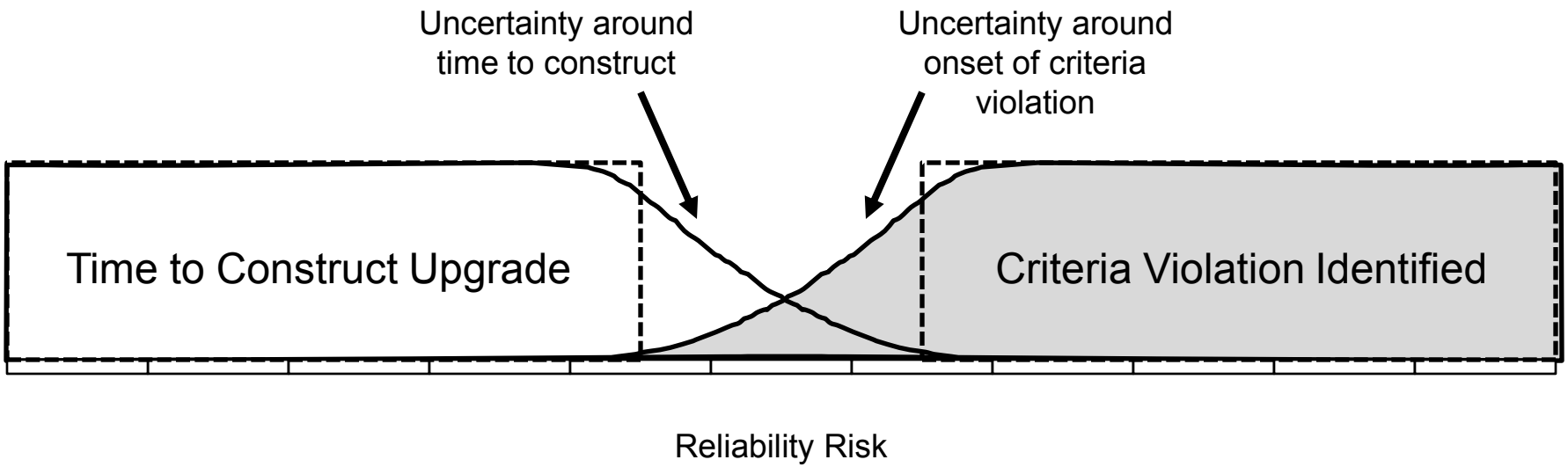
May be difficult to secure CPCN approval



Upgrade can not be completed in time – RMR or some operational solution required – otherwise system will not be reliable



Existing Bright-Line Decision Framework
The Reality

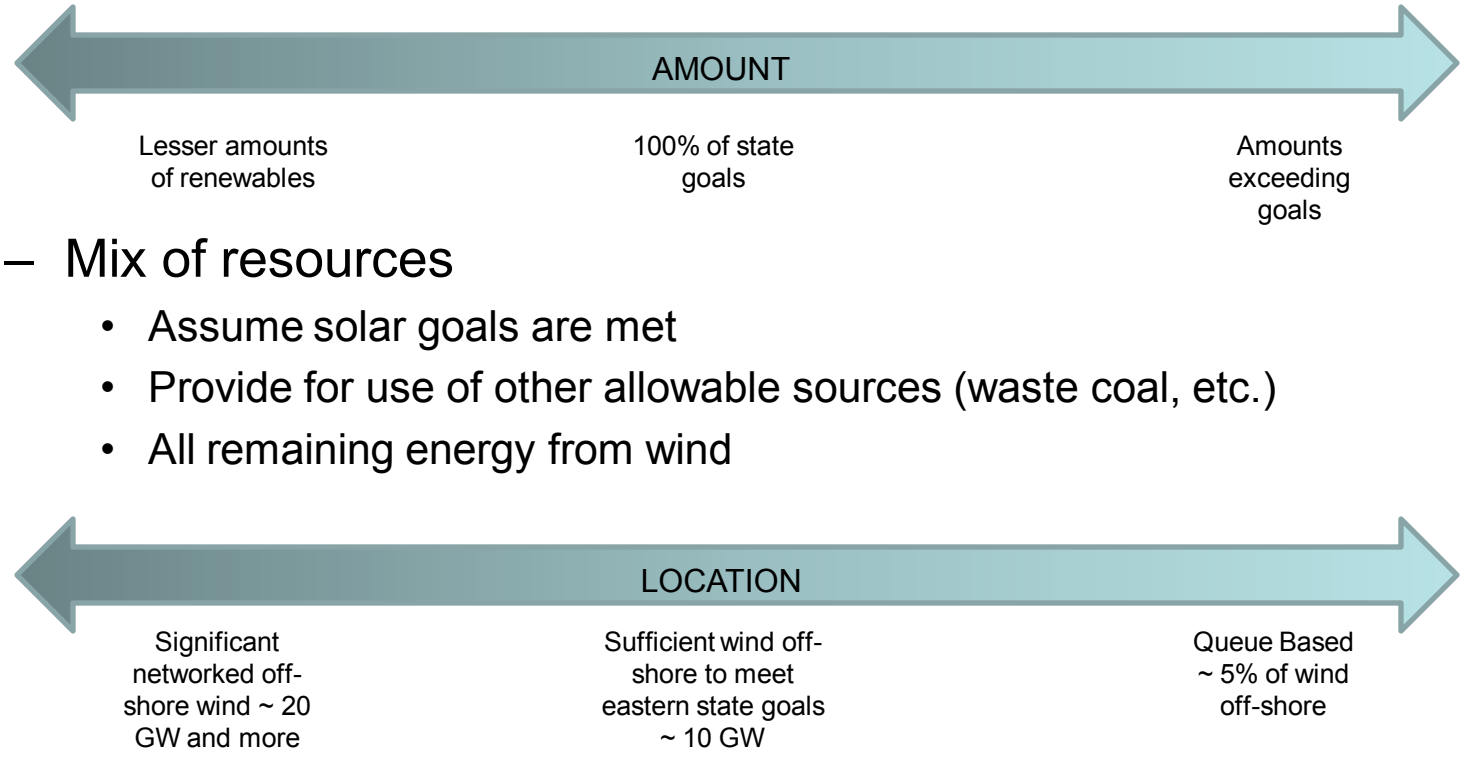


Baseline Reliability Analysis

- Change Approach to Load Forecast
  - Continue with evaluation of ITRON recommendations
  - Develop single forecast through year 3 for use in RPM analyses
  - Develop a range of forecasts over years 4 – 15 for use in RTEP analyses
- Include Some Treatment of At-Risk Generation
  - Remove generation not cleared in two RPM BRA from baseline analysis
    - Must deal with issue of publicly identifying generators
- Decision-Making
  - Introduce concept of dead band – trigger upgrades at 100%, but only remove when loadings drop below 95%

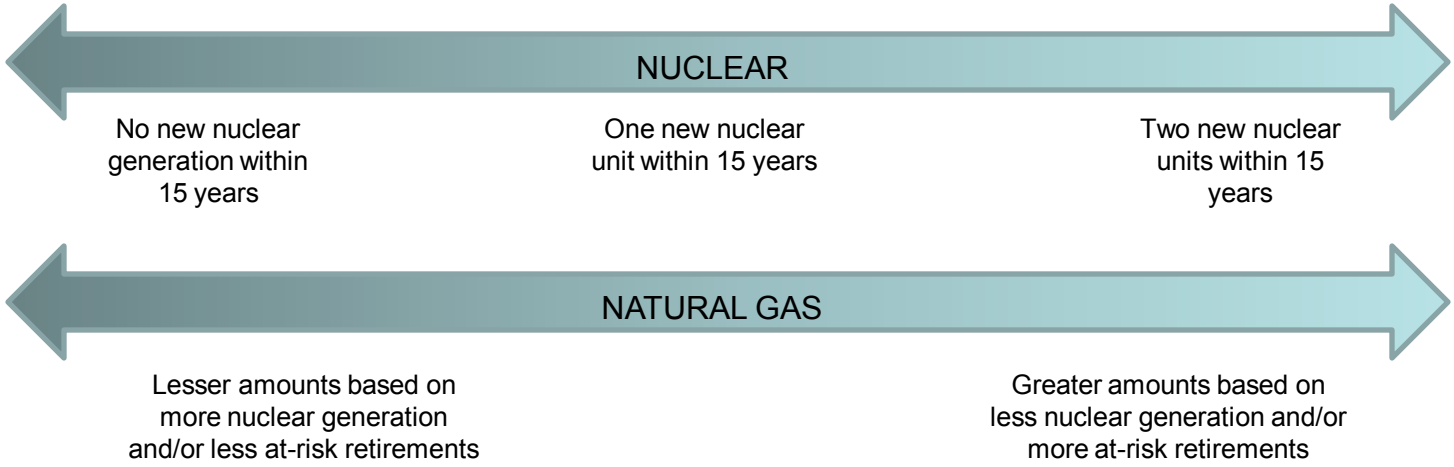
- Future generation mix
  - Renewable generation amounts and location
  - Natural gas development
  - Nuclear development
- At-risk generation
  - Amounts, timing, and location of retirements
- Demand response / energy efficiency
  - Degree to which goals are met
  - Impact of new DR products

- Renewable generation



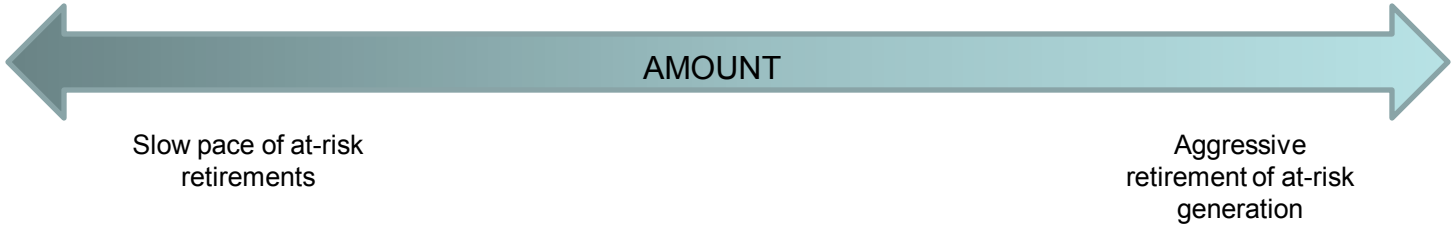
  - Mix of resources
    - Assume solar goals are met
    - Provide for use of other allowable sources (waste coal, etc.)
    - All remaining energy from wind
  - Fix amounts in Appalachian Mts. and vary off-shore against mid-West sources

- Other generation sources – assume 20% installed reserves



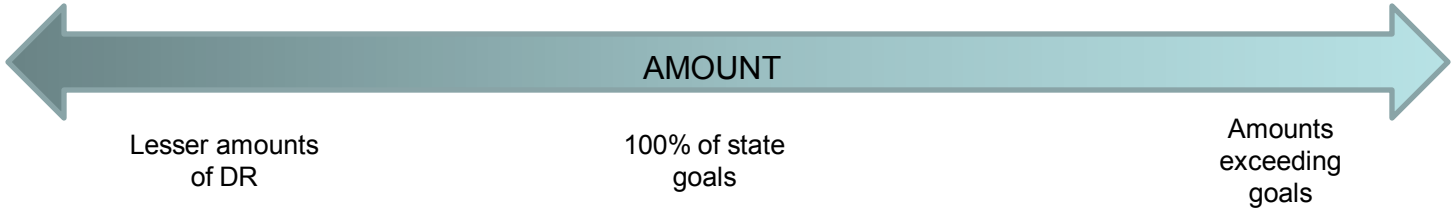
  - Vary natural gas generation development to balance 20% reserves with renewable development, nuclear development, and at-risk retirements
    - Location of natural gas generation based on interconnection queue

- At-Risk Generation



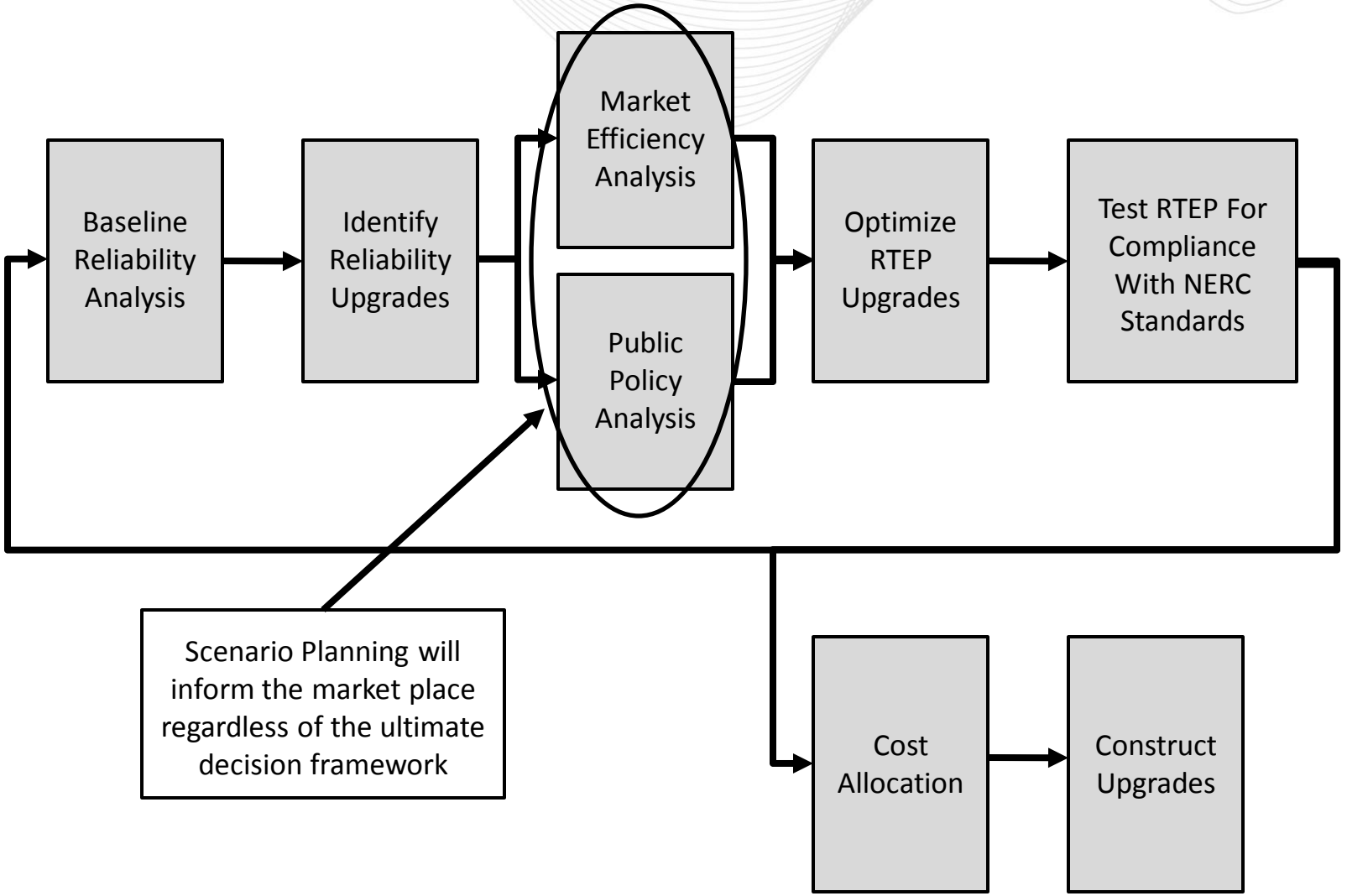
  - Track generation at-risk associated with environmental regulations
  - Track MMU revenue adequacy assessment for at-risk generation
  - Monitor generation not utilized in production cost simulations

- Demand Response

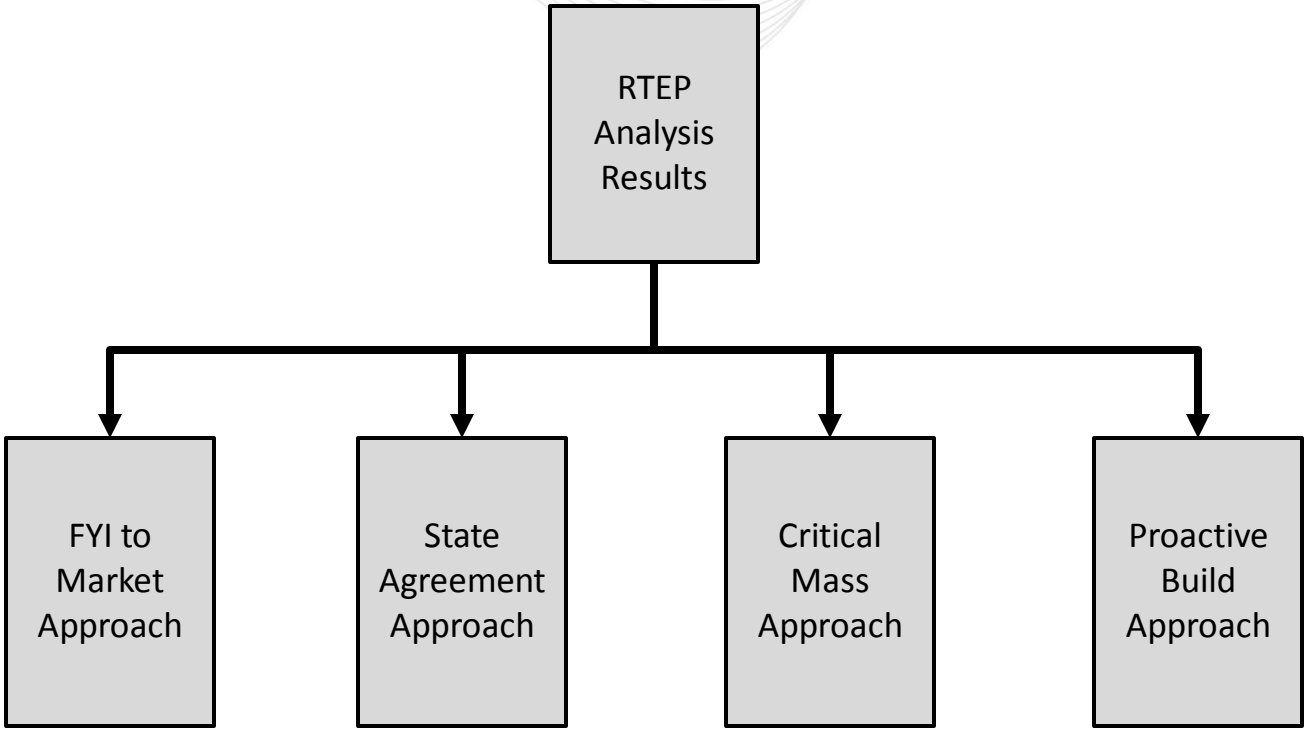


  - Track performance against state goals
  - Track traditional DR product trends as Price Responsive Demand behaviors evolve
  - Develop PRD modeling as experience is gained

General RTEP Framework



Decision Framework



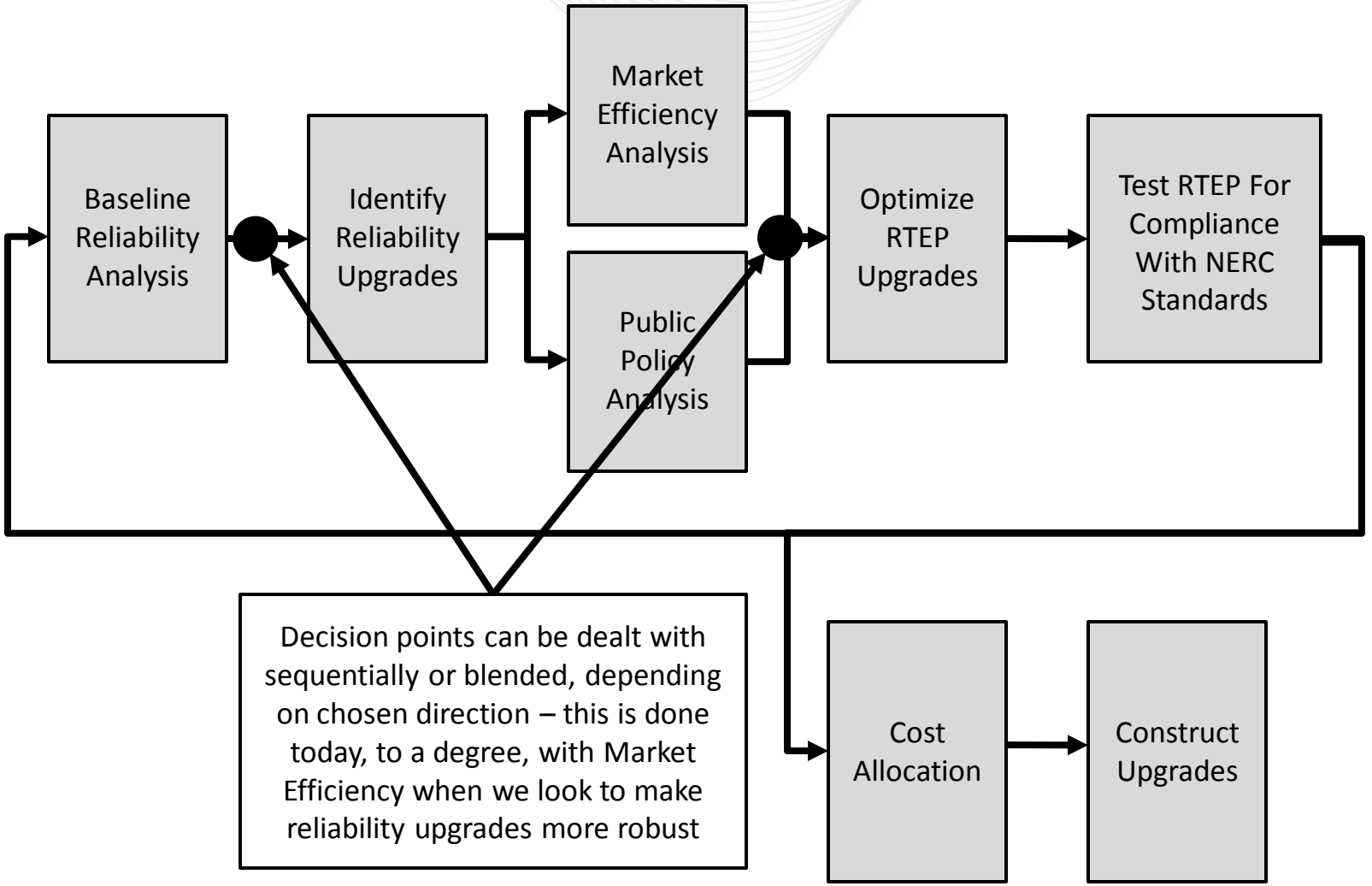
- FYI to Market Approach
  - Perform extensive scenario planning analysis
  - Provide results to market – allow market to decide what resources and associated transmission should proceed to meet goals other than reliability
  - Make no changes to RTEP decision-making
  - Make further changes to generation interconnection process to improve timeliness
  - Arguably satisfies requirement to consider public policy in planning process

- State Agreement Approach
  - Allows one or more states to decide how to meet goals if market does not provide
    - Integrate state selected projects into RTEP
    - Would require state-specific treatment of associated costs
  - Requires some form of tracking to associate specific resources with state-identified transmission upgrades
  - Requires mechanism to preserve capability of state-identified transmission upgrades as other needs arise
  - Requires some treatment of cost allocation related to state-identified transmission facilities

- Critical Mass Approach
  - Still allows states to decide how to meet goals through agreements
  - Allows major transmission projects for renewables to be included in RTEP when some percentage of associated generating capacity commits through an executed ISA
    - Provides for more efficient planning for large groups of resources
    - Allows transmission projects to get started before all generators are committed
    - Still allocates costs of transmission for renewables to generation projects – but, could move to an access fee approach which would allocate some costs to network customers
    - Leaves some risk for network customers if remaining capability for generators is never “signed up”

- Proactive Build Approach
  - Transmission will be included in RTEP to meet all goals
  - Will likely require a reworking of cost allocation procedures to account for different value associated with reliability versus market efficiency versus public policy of individual states
  - Raises question as to what to do with non-RPS generation or RPS generation beyond what is needed for goals

General RTEP Framework Decision Points



Next Steps

- Work with stakeholders to develop recommendations regarding strawman framework
- FERC filing must be made in December in order to implement changes in 2012 RTEP cycle
- Review by the MRC and MC would have to be in the September – November timeframe
- Provide recommendations to Board in September – November timeframe coincident with MRC and MC review
  - Decide on independent action if no consensus is achieved with stakeholders