PJM Planning Process Strawman

RPPTF
June 24, 2011
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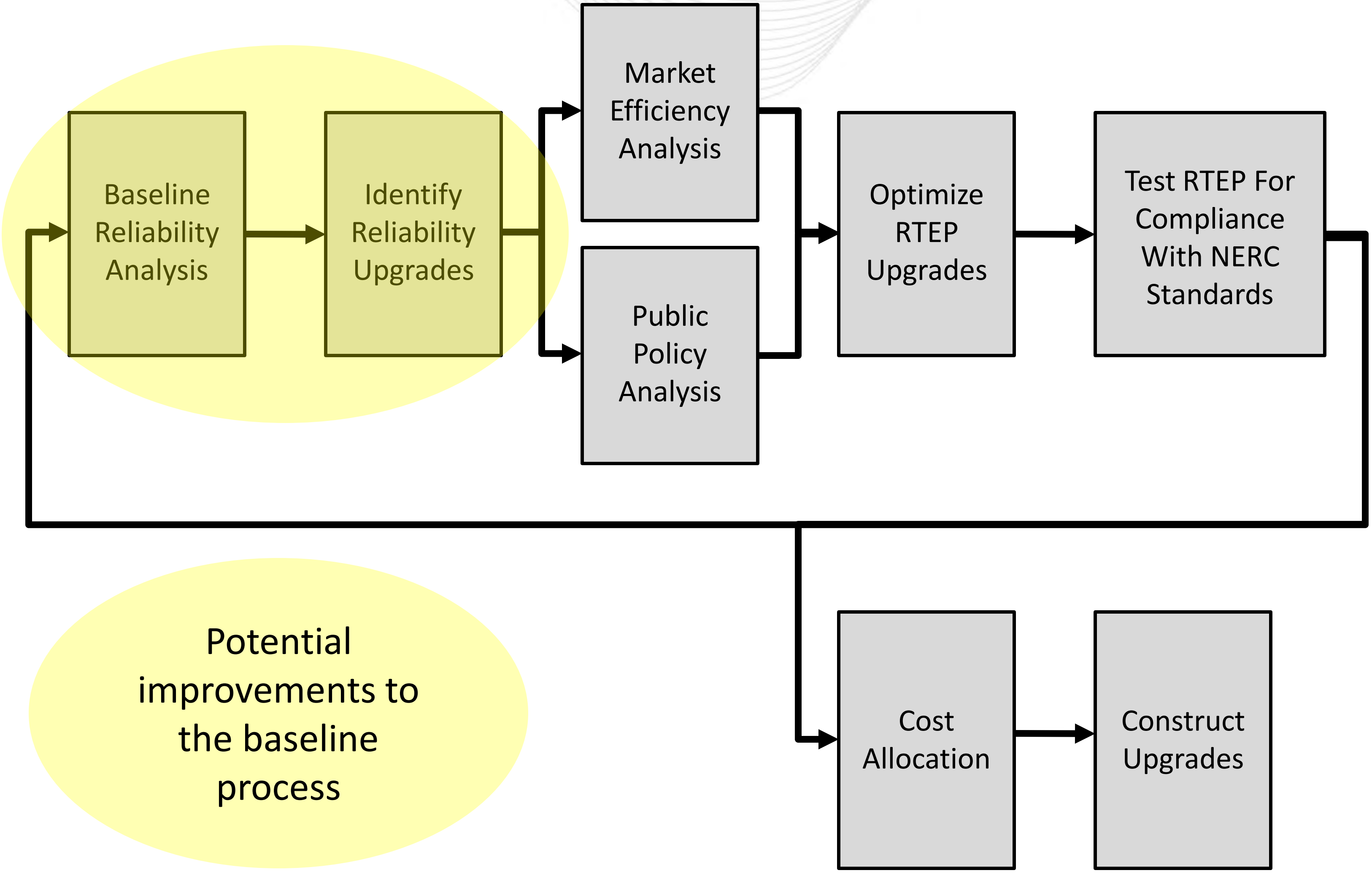
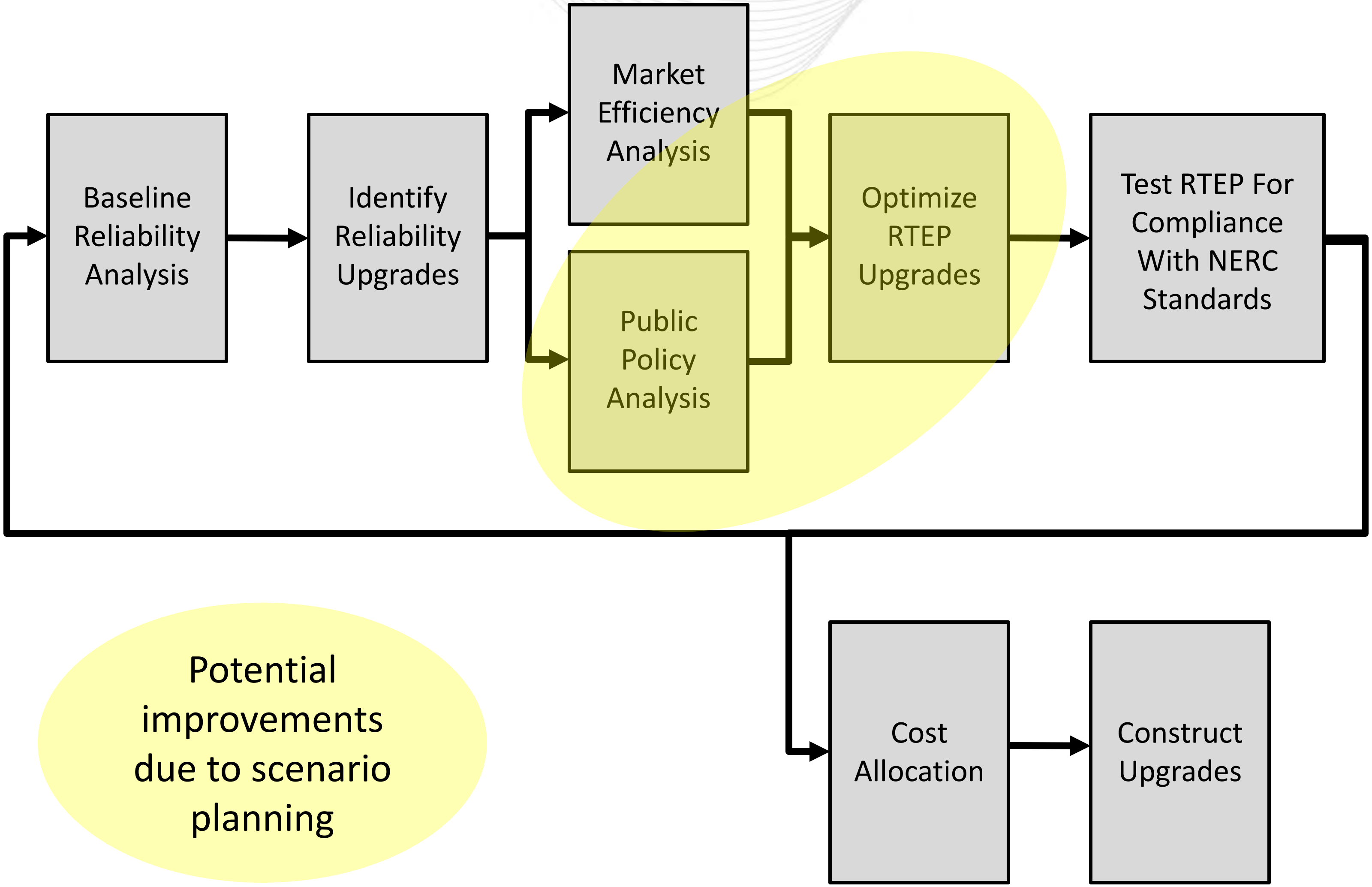
- Implement Changes to Base-Line Reliability Planning
  - Load Forecast
  - At-Risk Generation
  - Queued Generation
  - Decision Dead-band

General RTEP Framework



- Implement Changes Involving Scenario Planning
  - Decision Framework – Use All Four Elements in Different Situations
    - FYI Approach
    - State Agreement Approach
    - Critical Mass Approach
    - Proactive Build Approach
  - Implement Changes to Cost Allocation Based on Nature of Project, Drivers, and Decision Framework Approach Used

General RTEP Framework



- Change Approach to Load Forecast
  - Continue with evaluation of ITRON recommendations
  - Develop single forecast through year 3 for use in RPM analyses
    - Based on outcome of ITRON recommendations – average of Moody's and Global Insight or Index 1/2
  - Develop a range of forecasts over years 4 – 15 for use in RTEP analyses
    - Use single forecast in baseline vs. multiple forecasts in scenario analysis?
    - Use single econometric driver (Moody's?) vs. blend of multiple drivers?
    - Choice of load growth level for baseline – high, medium, low?

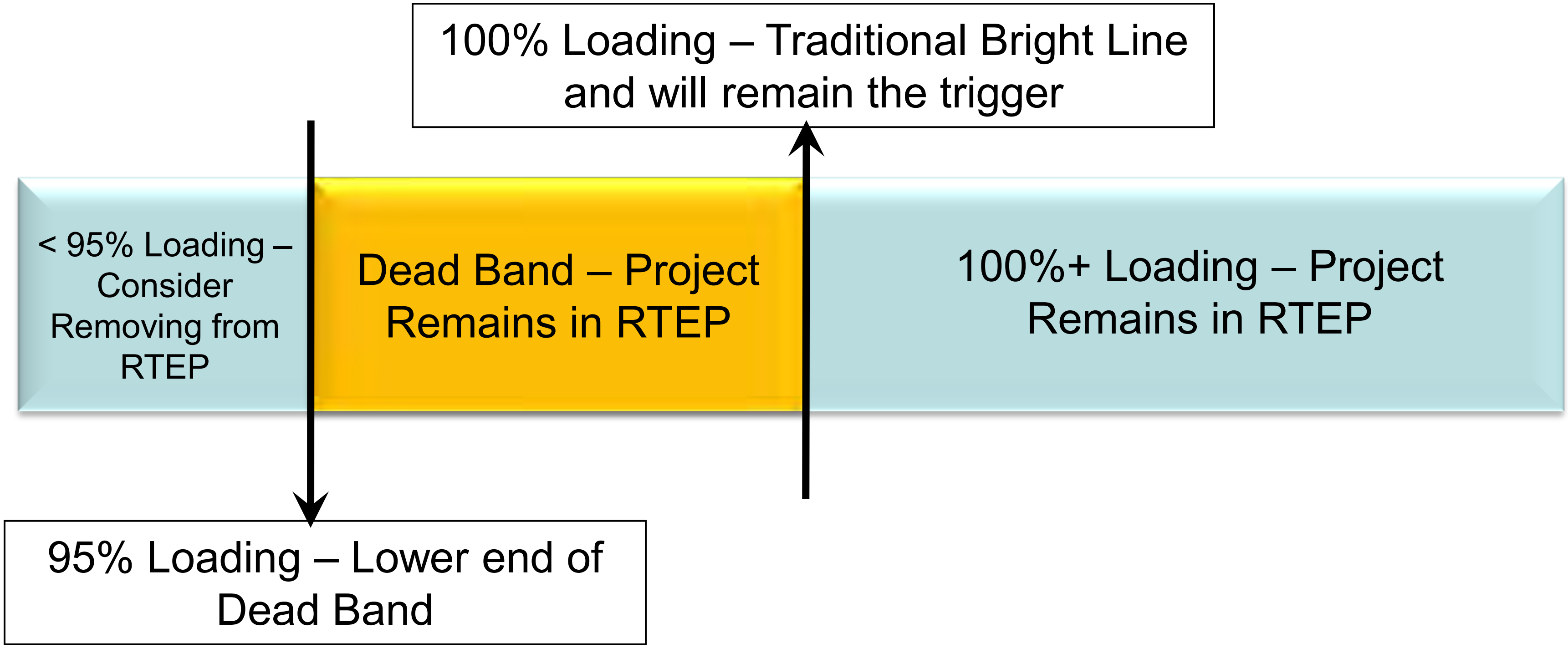
- Include Some Treatment of At-Risk Generation
  - Remove generation not cleared in two RPM BRA from baseline analysis
    - Issue with identifying generators that do not clear in RPM
  - Perform specific proactive retirement analyses for critical at-risk generation units
    - Identify required transmission upgrades to facilitate retirement
    - Maintain analysis confidentially, to be better prepared for retirement announcements
    - What criteria for selection of generators to study?

- Include Some Treatment of At-Risk Generation
  - Remove some portion of generation subject to environmental regulations from baseline
    - Increase CETO based on percentage of at-risk generation – leave individual generators in CETL analysis cases
  - Will identify more regional issues rather than local issues
  - May only utilize with respect to scenario analysis and decision framework (possibly Proactive Build)
  - Need to choose percentage of at-risk generation to evaluate
  - Study larger LDAs (global LDAs)
  - No issue of publicly identifying generators

- Change Treatment of Queued Generation
  - Defer treatment of queue to IPSTF
  - Include some portion of developing generation in baseline?
    - What criteria for inclusion?
    - Similar to Critical Mass concept?
  - Include generation with executed Facilities Study Agreement in RTEP (similar to ISA generation) to resolve criteria violations?
  - Remove generation with executed Facilities Study Agreement from all RTEP analysis?
    - True-up required RTEP upgrades after ISA is executed?
    - Resolve through queue process changes (IPSTF)?

Baseline Reliability Analysis

- Decision-Making
  - Introduce concept of dead band – trigger upgrades at 100%, but only remove when loadings drop below 95%



Decision Framework

FYI to Market Approach	State Agreement Approach	Critical Mass Approach	Proactive Build Approach
Enhanced Transparency and Information Flow to Market			
	Integrate State-Driven Projects		
		Trigger Projects Based on Combined Drivers and Trend of Generation Development	
			Trigger for Policy Bright Line

Decision Framework Elements

- FYI to Market Approach
  – Perform extensive scenario planning analysis
  – Provide wide range of results to market – allow market to decide what resources and associated transmission should proceed to meet goals other than reliability
  – Results could include performance of various solution options, but no action would be taken by PJM
  – Provide for greater stakeholder interaction on front and back end

- Cost Allocation Issues
  – None

Decision Framework Elements

- FYI to Market Approach
  - More extensive stakeholder discussion of input assumptions and scenarios for analysis
  - Discuss desired information with TEAC before each RTEP cycle
  - Produce text documents to support TEAC slides
  - More documentation of deliverability margins & limiting facilities
  - Discussion of assumption impacts

Decision Framework Elements

- State Agreement Approach
  - Allows one or more states to decide how to meet goals
  - Integrate state selected projects into RTEP
  - Need to define manner of commitment to project to insure on-going integrity of RTEP

- Cost Allocation Issues
  - Upgrades to be paid for by states sponsoring project – allocation to be determined by those states
  - Safe harbor for sponsoring states from costs to meet similar policy goals by other states
  - Allocation could be based on a blend of needs – see Critical Mass Approach

- State Agreement Approach
  - Stakeholder discussion of input assumptions and scenarios will provide for analysis of specific state policy initiatives
  - Analysis would identify all related upgrades to support chosen driver (e.g. satisfaction of RPS requirements)
  - Subsequent analyses would have to protect capability associated with state sponsored project
  - Projects do not need to be discrete – state needs could be met by some portion of capability of more robust projects
    - Allocation would consider sharing of capability across multiple needs

- Critical Mass Approach
  - Can be used to consolidate baseline reliability, market efficiency, and interconnection needs
  - Allows major transmission projects for renewables to be included in RTEP when some percentage of associated generating capacity commits through an executed ISA

- Cost Allocation Issues
  - Allocations for projects will likely be unique based on drivers
  - Develop guidelines based on drivers, but not specific formulaic approach
  - File specific project allocation for each project at FERC
  - Need to address identification of cost responsibility for generators using capability of Critical Mass projects

- Critical Mass Approach
  - Could couple with Proactive Build drivers or State Agreement drivers
  - Critical Mass projects can be based on:
    - Reliability drivers coupled with pending interconnection projects
    - At-risk generation drivers (through Proactive Build) coupled with pending interconnection projects
    - Pending interconnection projects, alone
    - Any of the above coupled with State Agreement project drivers
    - Any of the above coupled with Market Efficiency project drivers

- Critical Mass Approach
  - How do we integrate interconnection projects as drivers for a Critical Mass project?
    - Cannot perform System Impact Studies with and without Critical Mass project – would double the workload and make backlog issues worse
    - At-risk generation drivers (through Proactive Build) coupled with pending interconnection projects
    - Pending interconnection projects, alone
    - Any of the above coupled with State Agreement project drivers
    - Any of the above coupled with Market Efficiency project drivers
  - Need to identify cost allocation/assignment approach for interconnections (access fee vs. but-for vs. pro rata cost assignment)

- Critical Mass Approach
  - Need to identify cost allocation/assignment approach for interconnections (access fee vs. but-for vs. pro rata cost assignment)
    - Will not have identified a but-for cost via a System Impact Studies without Critical Mass project – again, would double the workload and make backlog issues worse
  - Attachment facilities would be identified separately and be a separate charge to the generator

- Critical Mass Approach
  - Access fee is simple to implement
    - Could be higher or lower than but-for cost for individual projects
    - Could leave some portion of project cost to be borne by network service customers
    - Could create different treatment for different projects in queue
      - Do we apply access fee to all generators?
      - Do we apply access fee only to renewable resources?
      - Do we apply access fee only to resources associated with Critical Mass projects?

- Critical Mass Approach
  - Pro-rata cost assignment is less simple to implement
    - Could be higher or lower than but-for cost for individual projects
    - Use of Critical Mass project may not be best indicator of contribution to multiple violations driving need to transmission upgrades
    - Use of portion of capability by other drivers may not be readily calculated to the MW
    - Should ensure that all project costs (portion not associated with other drivers) are borne by generators
    - Could create different treatment for different projects in queue

- Critical Mass Approach
  - What are appropriate triggers for examination of Critical Mass projects?
  - Could require that some portion of capability be associated with a “primary” driver, such as reliability
  - Possible need contribution from queued generation cannot be based on executed ISAs
    - If a generator already as an ISA, a fully developed set of but-for upgrades would already need to have been examined through a Facilities Study – generator would already be proceeding on that basis
    - Could use amount of generation in an area, but must recognize the potential drop-out rate

Decision Framework Elements

- Proactive Build Approach
  - Design “Bright Line” triggers related to various policy initiatives
  - Triggers will represent fairly high hurdles for proactive action

- Cost Allocation Issues
  - Depending on nature of trigger, cost allocation could follow current rules or be project specific (similar to Critical Mass)

- Proactive Build Approach
  - At-risk generation triggers will be defined for scenario analyses to coordinate with amounts removed in baseline
    - Lower levels of retirement of at-risk generation will require transmission upgrades in the RTEP
    - Trigger level to be determined
    - Criteria tests to be determined – load deliverability, NERC Category C?
    - Target regional, rather than local violations (may exclude NERC Category C)
    - Higher levels of retirement of at-risk generation will provide results for FYI and State Agreement Approaches
  - Other triggers can be identified in the future, but none are contemplated at this time

Assignment of Projects

- Need to re-open discussion of Right of First Refusal and issues related to the assignment of projects to builders
- Following slides are based on previous RPPTF materials and some background information

RTEP Transmission Projects

- Over 2500 discrete transmission projects approved
- Over $19 Billion of transmission infrastructure approved
- Projects have been primarily for reliability or for generator interconnection
  - $19 Billion includes projects related to over 56,000 MW of generation or merchant transmission interconnections
- Significant portion of reliability projects have been upgrades to existing infrastructure

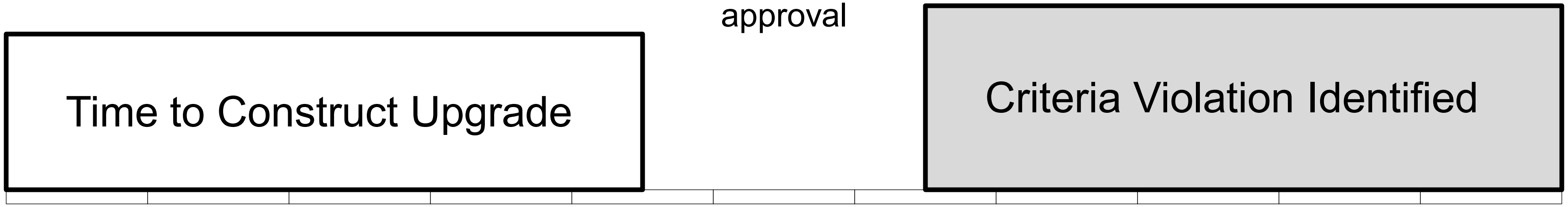
Merchant Transmission Projects

- Approximately 100 merchant transmission projects have been proposed
- 12 projects are in service
  - Includes 2 ties to NYC
  - Rest are accelerations of already approved RTEP upgrades or minor upgrades to existing infrastructure financed by merchant and built by transmission owner
- Remaining projects
  - Small number are related to ties to NYC
  - Most are accelerations of already approved RTEP upgrades or minor upgrades to existing infrastructure
  - Lately, a number of independent transmission projects have entered queue but desire recovery as regulated assets

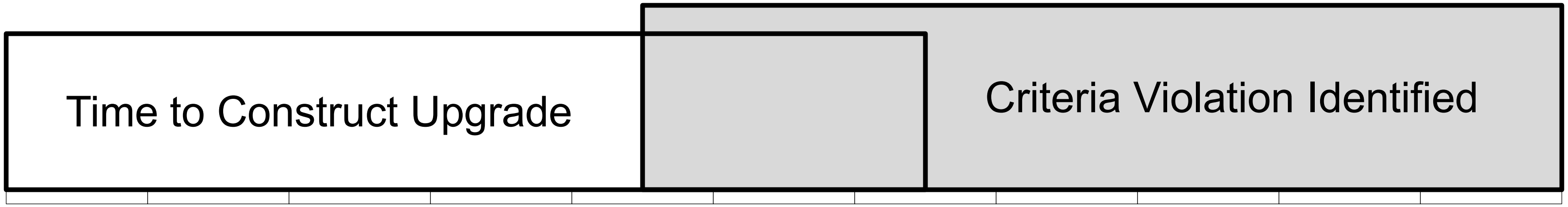
- Primary Power reactive system upgrades
  - Entered into the interconnection queue as merchant transmission projects
  - Requested consideration in RTEP and filed for rate treatment at FERC
- LS Power projects
  - Submitted for consideration as alternatives to existing RTEP projects or as new market efficiency projects
  - Filed for rate treatment at FERC
- Various announced projects (Green Power, Atlantic Wind, etc.)
  - Publicly announced but not specifically submitted for consideration in RTEP
  - Typically have filed for rate treatment at FERC

Existing Bright-Line Decision Framework

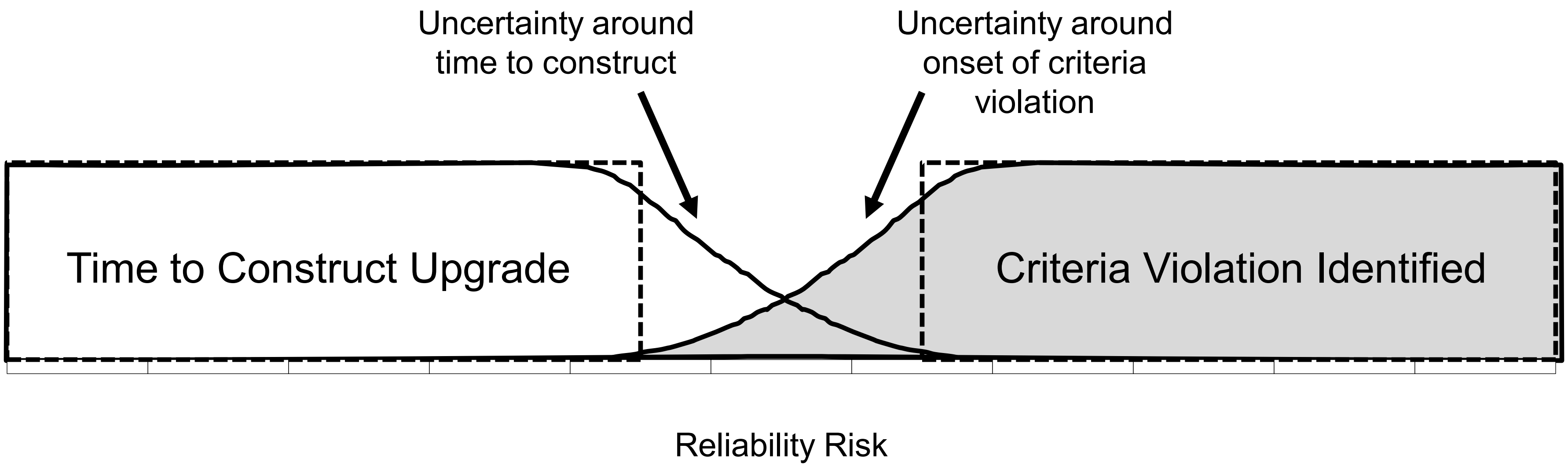
May be difficult to secure CPCN approval



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



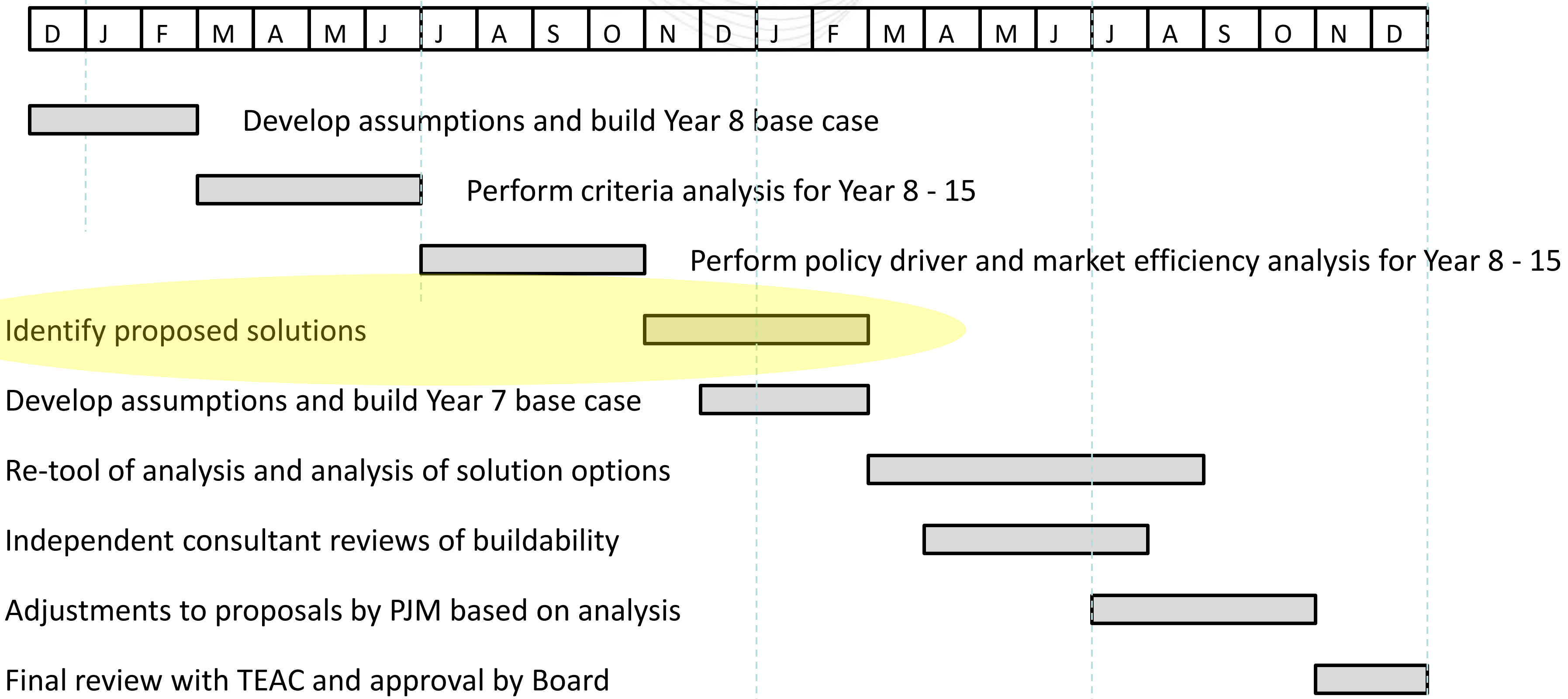
Existing Bright-Line Decision Framework
The Reality



- Should certain projects be the obligation of the local transmission owner, or would it be allowable for another party to take on that obligation?
  - Does the answer to that question depend upon the type of project?
    - Reliability projects
    - Market efficiency projects
    - Public policy projects
  - Does the answer to that question depend upon whether the project is an upgrade to existing infrastructure or whether it is new infrastructure?

- If other parties are allowed to build RTEP projects, how do we choose the builder?
  - Based on proposals
  - Based on bidding for PJM-identified projects
  - Other means of selecting?

RTEP Timeline



Proposal Process Concept

- Can solicit proposals to resolve issues identified in RTEP analysis
  - Reliability
  - Market Efficiency
  - Public Policy
- Likely to get many proposals with varying degrees of specificity
- Likely to get multiple proposals for fundamentally the same project
- PJM would likely need to identify an “optimal” project that is similar to a number of proposed projects, but not identical to any of them

Questions

- Will individual states allow parties, other than the local transmission owner, to build RTEP upgrades?
  - Would that be permissible under State laws regarding “public utilities” whether or not eminent domain were needed to be exercised?
  - When would a state need to make that determination? Before the project is approved to include in the PJM RTEP? After the project is filed with the state for CPCN/siting approval?
- If non-transmission owners are allowed to build, does this change the existing obligation to build of the transmission owners?
- Should some sub-set of RTEP projects be reserved to be the responsibility of the transmission owners?
  - Reliability-based?
  - Upgrades to existing infrastructure?
- What qualifications must be in place for non-transmission owner builders?

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