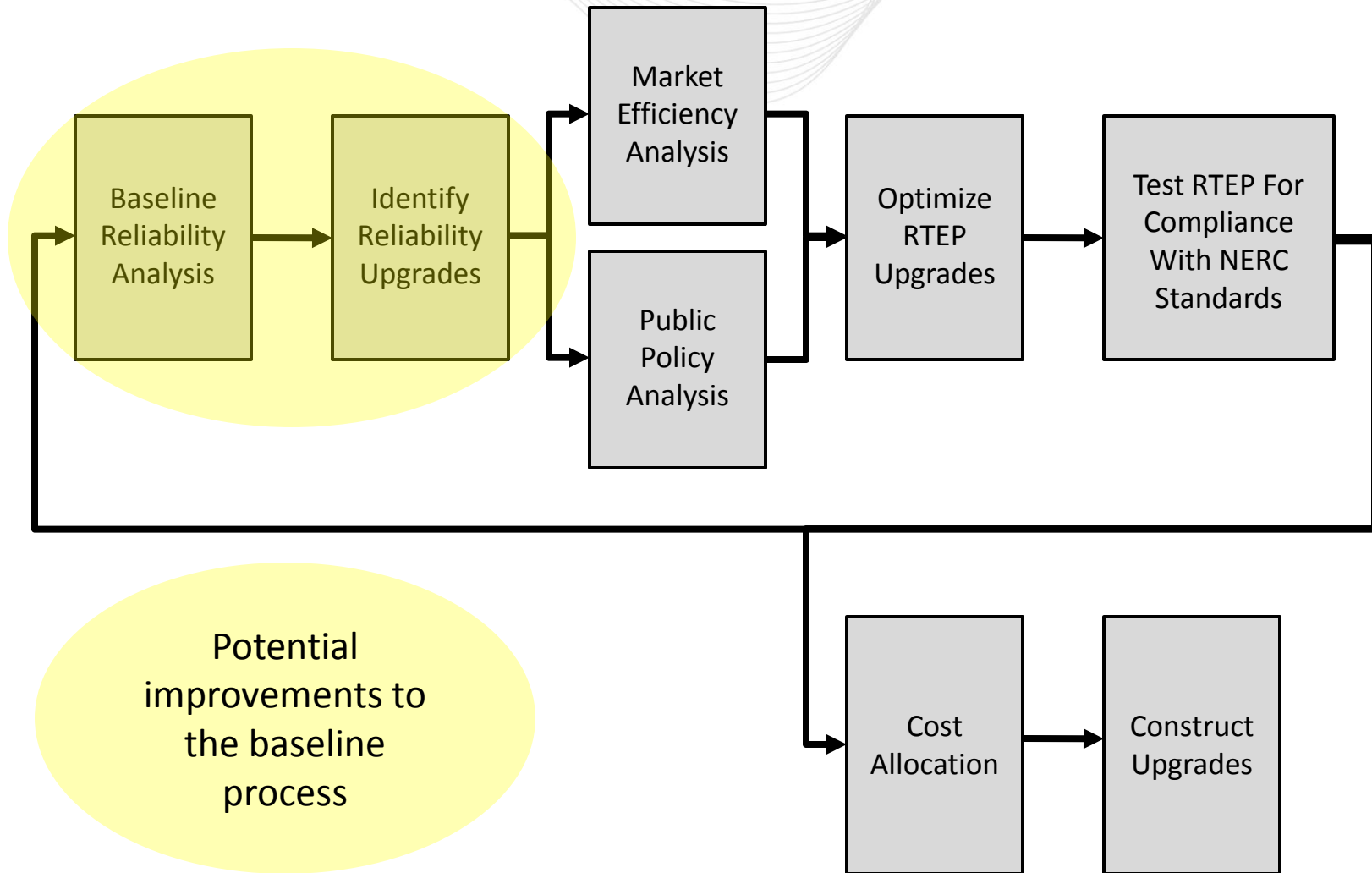


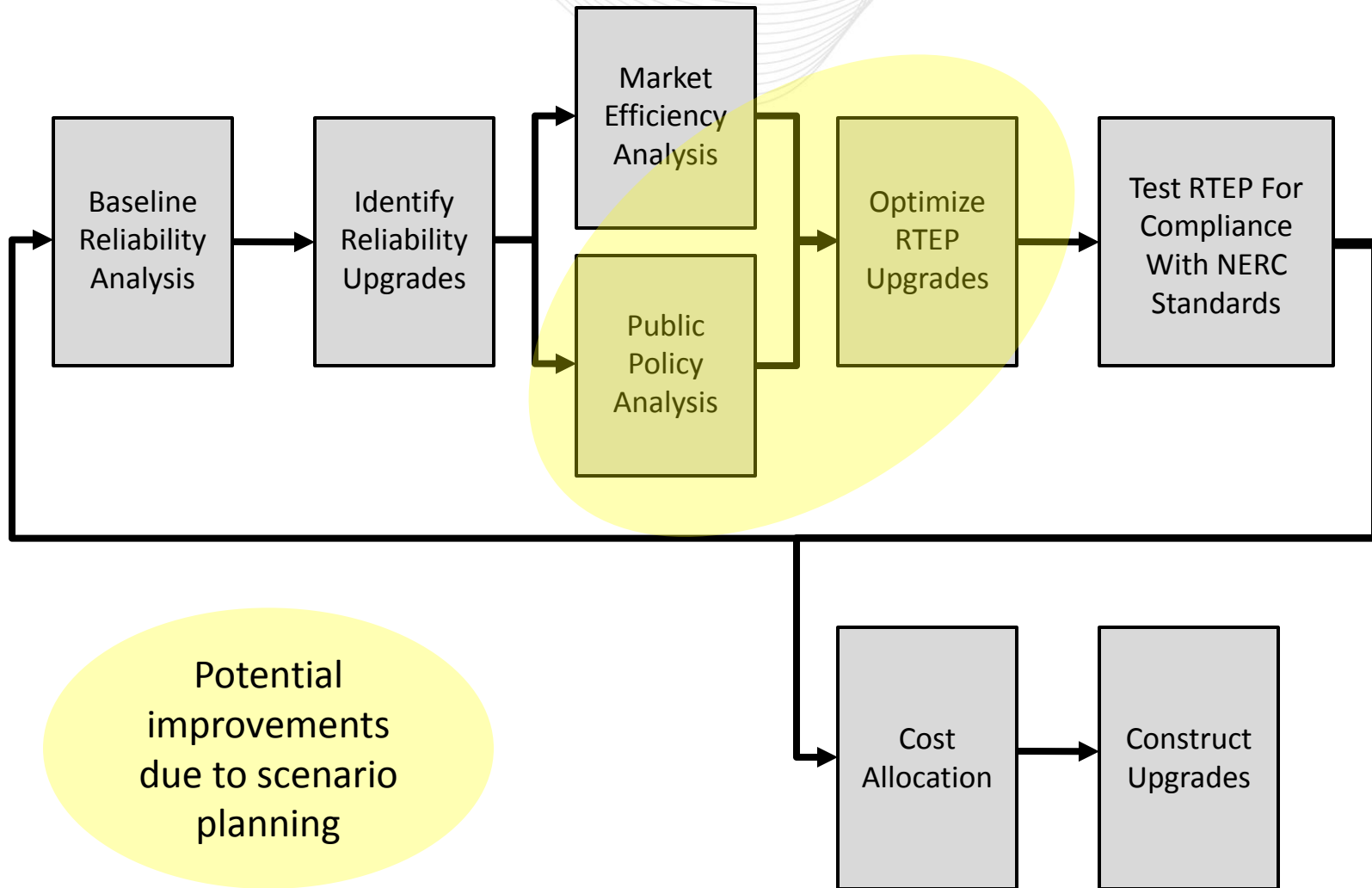
PJM Planning Process Strawman

RPPTF
June 24, 2011
Steve Herling

- Implement Changes to Base-Line Reliability Planning
 - Load Forecast
 - At-Risk Generation
 - Queued Generation
 - Decision Dead-band



- **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



- 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?

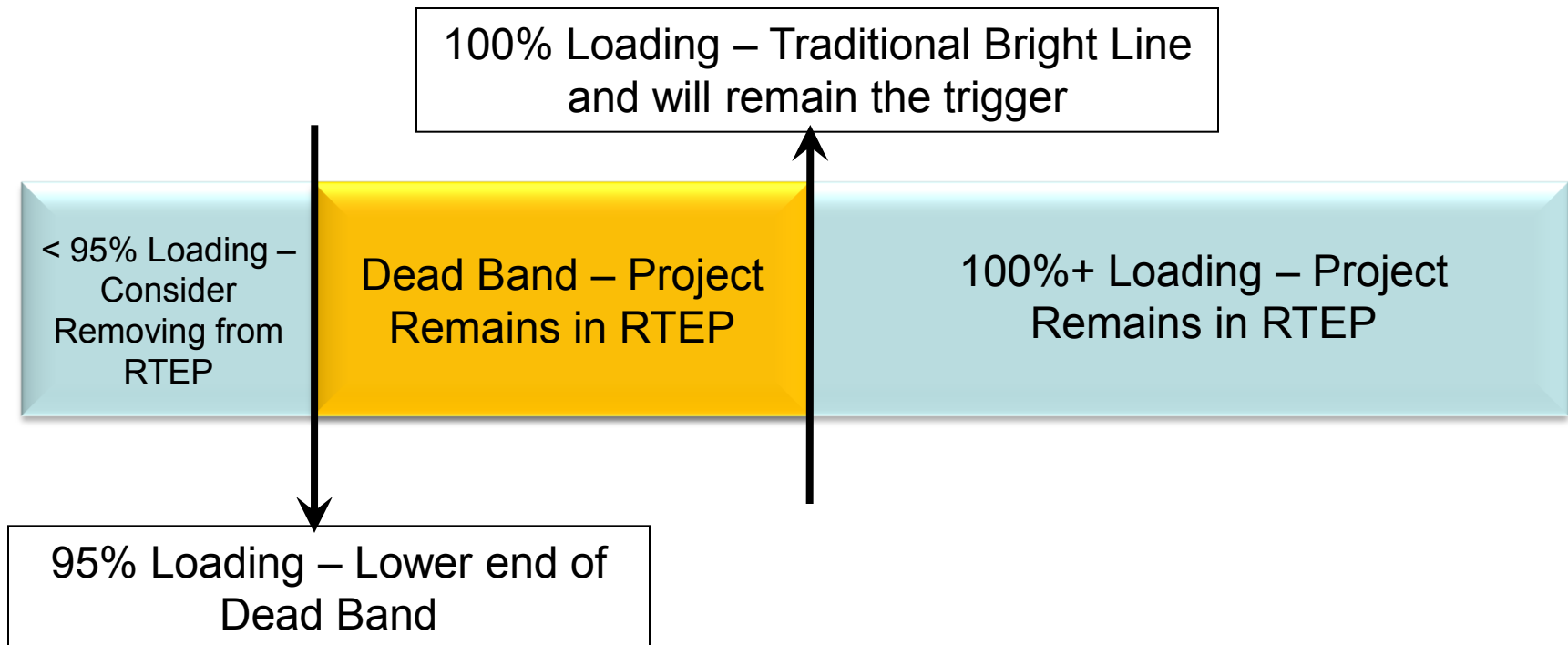
- **Include Some Treatment of At-Risk Generation**
 - Remove generation not cleared in two RPM BRA from baseline analysis
 - Issue with identifying generators that do not clear in RPM
 - Perform specific proactive retirement analyses for critical at-risk generation units
 - Identify required transmission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

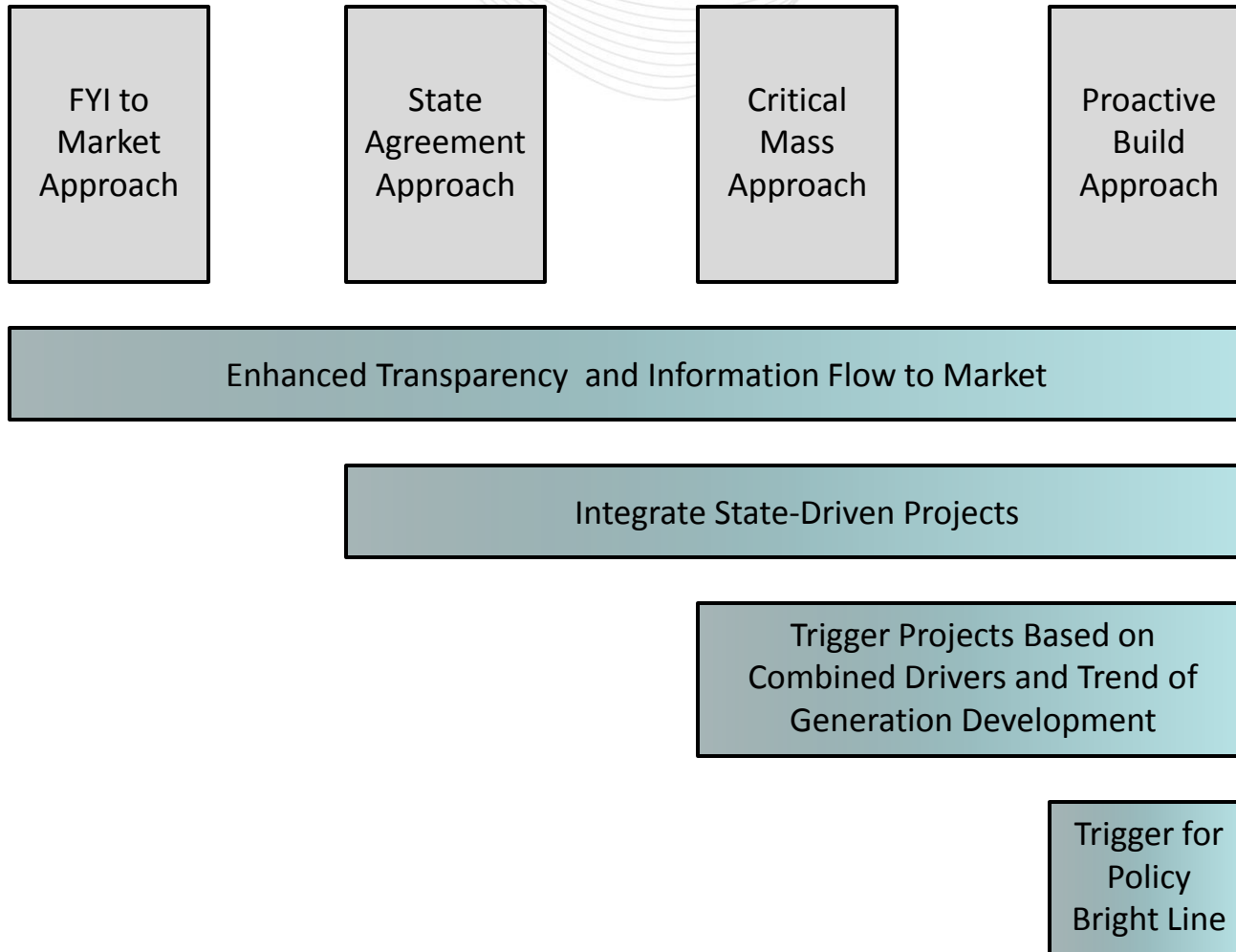
- Include Some Treatment of At-Risk Generation
 - Remove some portion of generation subject to environmental regulations from baseline
 - Increase CETO based on percentage of at-risk generation – leave individual generators in CETL analysis cases
 - Will identify more regional issues rather than local 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)?

- **Decision-Making**

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





- 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

- 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

- **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

- **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

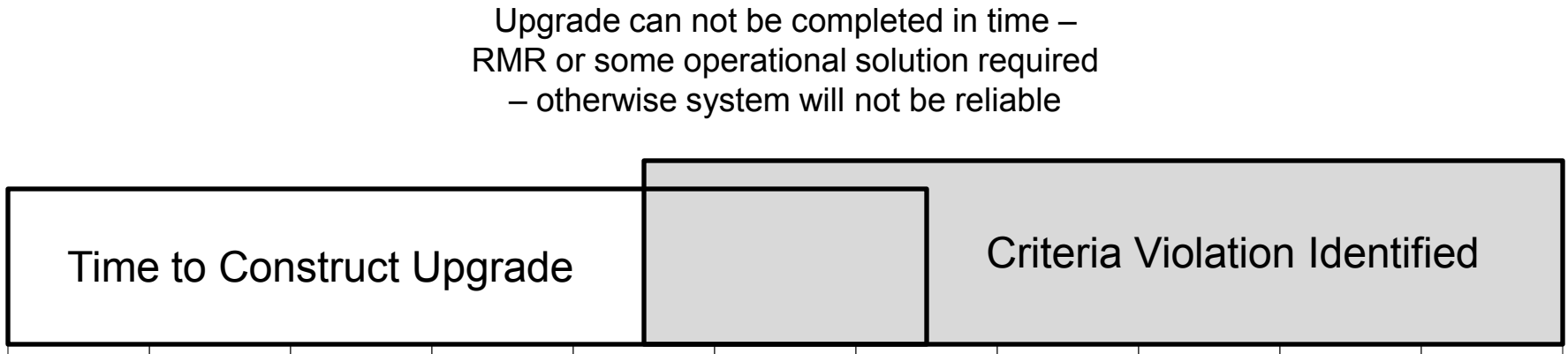
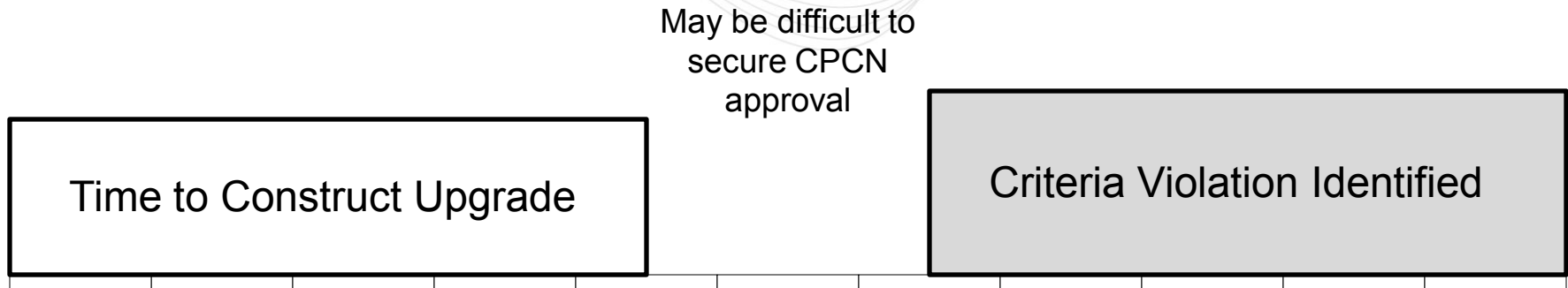
- Need to re-open discussion of Right of First Refusal and issues related to the assignment of projects to builders
- Following slides are based on previous RPPTF materials and some background information

- 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

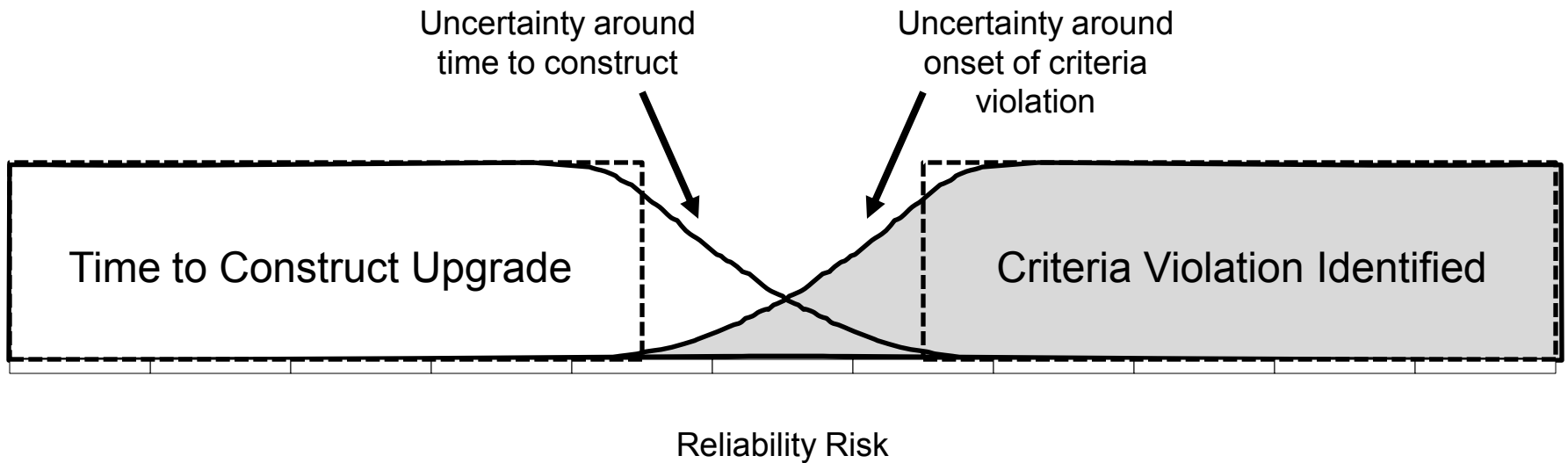
- Approximately 100 merchant transmission projects have been proposed
- 12 projects are in service
 - Includes 2 ties to NYC
 - Rest are accelerations of already approved RTEP upgrades or minor upgrades to existing infrastructure financed by merchant and built by transmission owner
- Remaining projects
 - 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

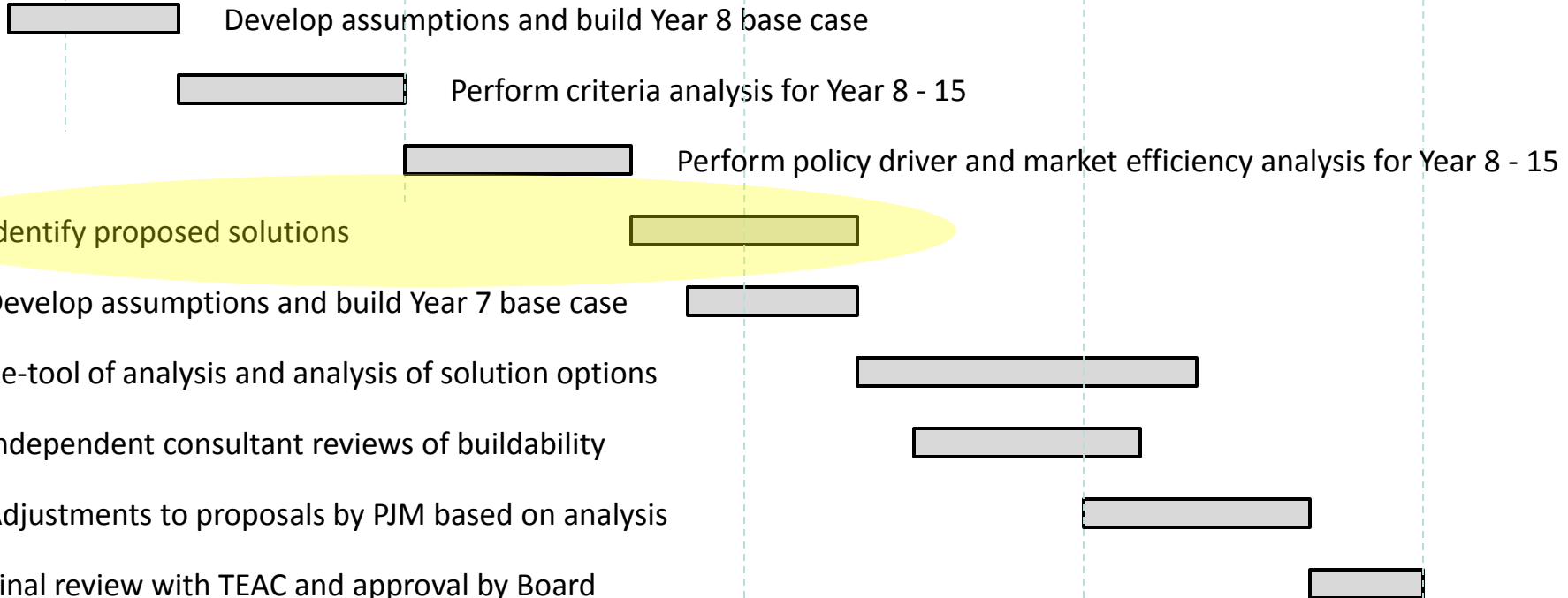


Existing Bright-Line Decision Framework The Reality



- 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?



- 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

- 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?

- 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