California ISO

Transmission Economic Assessment Methodology (TEAM)

(DRAFT)

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Executive Summary

ES.1 Purpose of this Document

Transmission Economic Assessment Methodology (TEAM) [1] proposed principles for economic planning and outlined a framework to implement these principles. TEAM was first proposed by the ISO as the methodology for transmission economic assessment in 2004. While the general applicability of the main concepts has been proven, implementations of TEAM principles have changed since then along with the power market evolution and renewable integration, and the progress of study stools and models. The CAISO considers it necessary to update the TEAM document to reflect current practices and interpretations, and remove obsolete detail from existing document, as process improvement for the current planning processes as well as to set a more meaningful foundation for any future discussions.

ES.2 Key Principles of the Evaluation Methodology

There are aspects of our methodology we consider critical for any economic evaluation of transmission upgrades. We call these aspects *"key principles*". Other aspects of our methodology are evolving as the modeling and analytical technology improves. We identify and discuss these *"potential enhancements"* in later portions of the report.

Although the specific application of the key principles may vary from study-to-study, the CAISO requires that the following five requirements be considered in any economic evaluation of proposed transmission upgrades presented to the CAISO for review.

ES.2.1 Benefit Framework

TEAM provides a standard for measuring transmission expansion benefits for consumers, producers, and transmission owners. While the original methodology explored a range of perspectives, the "ratepayer" perspective has been relied upon consistently since the methodology was introduced. Other options that had been considered initially and subsequently discarded were society and participant perspectives. However, WECC societal benefit perspective is used as well in order to assess if there is any impact on the system level of the entire WECC system.

[1] http://www.caiso.com/Documents/TransmissionEconomicAssessmentMethodology.pdf

TEAM original document focused on production benefit assessment based on production cost simulation. Additional benefits were discussed, but lacked details of implementation due to data and modeling limitations at the time when TEAM was introduced. In the current ISO's planning practice, benefits can be categorized into:

- Production benefits: Benefits resulting from changes in the net ratepayer payment based on production cost simulation as a consequence of the proposed transmission upgrade.
- Capacity benefits: Benefits resulting from increased importing capability into the CAISO BAA or into an LCR area. Decreased transmission losses and increased generator deliverability contribute to capacity benefits as well.
- Public-policy benefit: Transmission projects can help to reduce the cost of reaching renewable energy targets by facilitating the integration of lower cost renewable resources located in remote area, or by avoiding over-build.
- Renewable integration benefit: Interregional transmission upgrades help mitigate integration challenges, such as over-supply and curtailment, by allowing sharing energy and ancillary services (A/S) among multiple BAAs.
- Avoided cost of other projects: If a reliability or policy project can be avoided because of the economic project under study, then the avoided cost contribute to the benefit of the economic project.

ES.2.2 Network Representation

In order to perform a correct economic assessment of an upgrade, the actual physical impact of the upgrade has to be modeled correctly. Accurate physical transmission modeling is also important to ensure that reliability and delivery standards are achieved. Since these standards are based on physical line flows, a full network model is implemented, satisfying the following requirements:

Table ES-1: Production Cost Simulation Requirements Relating to the Network Model Requirement

No	Requireme
1	Must use a network model that is derived from a WECC power flow case.
2	Performs either a DC or AC OPF that correctly models the physical power flows on transmission facilities for each specific hourly load and generation pattern.
3	Capable of modeling and enforcing individual facility limits, linear nomograms, and path limits.
4	Capable of modeling limits that vary based on variables such as area load, facility loading, or generation availability.
5	Capable of modeling transmission limits
6	Models phase shifters, DC lines, and other significant controllable devices
7	Capable of calculating nodal prices.

8	Capable of plotting the hourly flows (either chronologically or by magnitude) on individual facilities, paths, or nomograms.
9	While not required, it is desirable for the simulations to model transmission losses.

ES.2.3 Market Prices

Modeling the underlying prices is the basis for any economic assessment. A new transmission project can enhance market competitiveness by both increasing the total supply that can be delivered to consumers and the number of suppliers that are available to serve load. In a liberalized electricity market, suppliers are likely to optimize their bidding strategies in response to such changing system conditions or observed changes in the behavior of other market participants. Theoretically, strategic bidding can be modeled using game theoretic or empirical approaches.

However, in the long term, no generator can operate below its short run marginal cost. Furthermore, the current market design performs market power mitigation. Additionally, strategic bidding is closely related to the location and technology of certain generators. Due to the long-term horizon of transmission planning, the existence of these circumstances favoring strategic bidding is uncertain. This uncertainty is assumed to be greater than the added value of including strategic bidding in the analysis.

As a consequence, in the ISO’s current economic planning studies, cost-based production cost simulation is used.

ES.2.4 Uncertainty

Decisions on whether to build new transmission are complicated by risks and uncertainties about the future. Future load growth, fuel costs, additions and retirements of generation capacities and the location of those generators, and availability of hydro resources are among some of the many factors impacting decision making. Some of these risks and uncertainties can be easily measured and quantified, and some cannot.

The economic assessment of a proposed transmission upgrade can be sensitive to specific input assumptions. Sensitivity studies are needed to test the robustness of the economic assessment results. In the ISO’s current practice, sensitivity cases are created by varying the most critical assumptions for the project under evaluation. Such cases may include high load growth, high gas prices, wet or dry hydrological years, and different resource plans.

ES.2.5 Evaluating Alternatives for Transmission Expansion

The evaluation of alternatives to a proposed transmission upgrade is an integral part of the ISO’s transmission planning process. If a more cost-effective solution is identified that solves the same problem as a transmission upgrade proposed by a potential project sponsor, the proposed upgrade is not assessed further. The test for alternatives includes modified operating procedures and additional special protection schemes (SPS). These tests are performed in reliability studies.

Economic assessment is performed for projects that are proposed by potential project sponsors and that are found to significantly alleviate congestion. If there are several proposals that are found to mitigate the same congestion, the alternatives are compared and the most cost-effective one is the preferred solution.

ES.3 Applicability of Methodology

The five key principles of the proposed CAISO methodology do not need to be applied in exacting detail for each study. Rather, the type of study and initial study results will dictate at what level the principles should be applied.

For all transmission upgrade studies, we will require as a minimum, the use of a transmission network model and the consideration of alternatives. I f preliminary economic feasibility studies show the proposed upgrade to be strongly economic from CAISO ratepayer perspective and no negative impact to the WECC system, then uncertainty analyses may not be necessary. If the economic benefits are marginal, uncertainty analyses may be needed to better understand the distribution of benefits and their root causes.

ES.4 Potential Enhancements

As stated at the beginning of this summary, the CAISO-proposed methodology is based on five key principles. Although these principles were established as requirements, their exact implementation is subject to enhancements, as suggested by the experiences and practical needs along with the constant application of the methodology. For example, the ISO works with WECC and other planning regions to continuously improve the transmission and market modeling. Also a potential enhancement of applying a stochastic approach for a range of parameters could create additional analytical value. It is worth noting that there is not an exhaustive list of potential enhancements as the process and practical need evolve.

ES.5 CAISO Decision Process

TEAM framework serves as consistent means of conducting a project evaluation. If a sponsor does not privately finance a project, and a proposal is submitted to the CAISO for funding through an access charge, the CAISO will utilize the TEAM framework to evaluate project economics. The project must receive a favorable evaluation prior to being recommended the CAISO Board approve it.

The CAISO will primarily rely on ISO ratepayer perspective when evaluating the economic viability of a potential transmission upgrade. Additionally, the societal perspective is applied as a test for the benefit of the whole WECC region. This second perspective is especially considered for upgrades with interregional impacts.

Regarding interregional project, other perspectives may be evaluated to determine if other parties will benefit from the potential upgrade and can contribute to the capital cost of the upgrade. This evaluation will help to identify if large amounts of benefits transfer from one region to another or one market participant to another. Although not everyone may be compensated for a change in regional prices, the ultimate aim of an upgrade is to improve productive efficiency so all load may be served at a lower cost.

ES.6 CA Regulatory Framework for Transmission Evaluation

The regulatory framework for the economic assessment of transmission assets is outlined in the tariff section 24.3.1 and specified in the corresponding business practice manual for the transmission planning process.

ES.7 Conclusion

TEAM provided principles and a framework for economic planning studies. Implementations of TEAM principles have changed as the environment changes. This updated document provides a summary of the application of TEAM in ISO’s economic planning practices and the corresponding updates in the TEAM implementation, including removing the obsolete components, while the framework of TEAM remains the same.

1. Overview of Transmission Planning Process

The TEAM methodology is intended to be a tool for providing market participants, policy-makers, and permitting authorities with information necessary to make informed decisions when planning and constructing a transmission network for reliable and efficient delivery of electric power to California consumers. This section of the TEAM report discusses the current transmission planning and siting process and demonstrates how the TEAM methodology enhances that process. It also identifies changes in the regulatory environment that are occurring, or may occur in the near future.

The annual planning process is structured in three consecutive phases with each planning cycle identified by a beginning year and a concluding year. Each annual cycle begins in January but extends beyond a single calendar year. The 2014-2015 planning cycle, for example, began in January 2014 and concluded in March 2015.

Phase 1 includes establishing the assumptions and models for use in the planning studies, developing and finalizing a study plan, and specifying the public policy mandates that planners will adopt as objectives in the current cycle. This phase takes roughly three months from January through March of the beginning year.

Phase 2 is when the ISO performs studies to identify the needed solutions to the various needs that culminate in the annual comprehensive transmission plan. This phase takes approximately 12 months that ends with Board approval. Thus, phases 1 and 2 take 15 months to complete. The identification of non-transmission alternatives that are being relied upon in lieu of transmission solutions also takes place at this time. It is critical that parties responsible for approving or developing those non-transmission alternatives are aware of the reliance being placed on those alternatives.

Phase 3 includes the competitive solicitation for prospective developers to build and own new transmission facilities identified in the Board-approved plan. In any given planning cycle, phase 3 may or may not be needed depending on whether the final plan includes transmission facilities that are open to competitive solicitation in accordance with criteria specified in the ISO tariff.

In addition, specific transmission planning studies necessary to support other state or industry informational requirements can be incorporated into the annual transmission planning process to efficiently provide study results that are consistent with the comprehensive transmission planning process. In this cycle, these studies focus primarily on beginning the transition of incorporating renewable generation integration studies into the transmission planning process.

Phase 1 generally consists of two parallel activities: 1) developing and completing the annual unified planning assumptions and study plan; and 2) developing a conceptual statewide transmission plan, which may be completed during phase 1 or phase 2. The generating resource portfolios used to analyze public policy-driven transmission needs were developed as part of the unified planning assumptions in phase 1.

The purpose of the unified planning assumptions is to establish a common set of assumptions for the reliability and other planning studies the ISO will perform in phase 2. The starting point for the assumptions is the information and data derived from the comprehensive transmission plan developed during the prior planning cycle. The ISO adds other information, including network upgrades and additions identified in studies conducted under the ISO's generation interconnection procedures and incorporated in executed generator interconnection agreements (GIA). In the unified planning assumptions the ISO also specifies the public policy requirements and directives that will affect the need for new transmission infrastructure.

The study plan describes the computer models and methodologies to be used in each technical study, provides a list of the studies to be performed and the purpose of each study, and lays out a schedule for the stakeholder process throughout the entire planning cycle. The ISO posts the unified planning assumptions and study plan in draft form for stakeholder review and comment, during which stakeholders may request specific economic planning studies to assess the potential economic benefits (such as congestion relief) in specific areas of the grid. The ISO then specifies a list of high priority studies among these requests (i.e., those which the engineers expect may provide the greatest benefits) and includes them in the study plan when it publishes the final unified planning assumptions and study plan at the end of phase 1. The list of high priority studies may be modified later based on new information such as revised generation development assumptions and preliminary production cost simulation results.

The conceptual statewide transmission plan, also added to the planning process in 2010, was initiated based on the recognition that policy requirements or directives such as the renewables portfolio standard apply throughout the state, not only within the ISO area. The conceptual statewide plan takes a whole-state perspective to identify potential upgrades or additions needed to meet state and federal policy requirements or directives such as renewable energy targets. The ISO performs this activity in coordination with regional planning groups and neighboring balancing authorities to the extent possible.

In **phase 2**, the ISO performs all necessary technical studies, conducts a series of stakeholder meetings and develops an annual comprehensive transmission plan for the ISO controlled grid. The comprehensive transmission plan specifies the transmission solutions to system limitations needed to meet the infrastructure needs of the grid. This includes the reliability, public policy, and economically driven categories. In phase 2, the ISO conducts the following major activities:

- performs technical planning studies as described in the phase 1 study plan and posts the study results;

- provides a request window for submitting reliability project proposals in response to the ISO's technical studies, demand response storage or generation proposals offered as alternatives to transmission additions or upgrades to meet reliability needs, Location Constrained Resource Interconnection Facilities project proposals, and merchant transmission facility project proposals;
- completes the conceptual statewide plan if it is not completed in phase 1, which is also used as an input during this phase, and provides stakeholders an opportunity to comment on that plan;
- evaluates and refines the portion of the conceptual statewide plan that applies to the ISO system as part of the process to identify policy-driven transmission elements and other infrastructure needs that will be included in the final comprehensive transmission plan;
- coordinates transmission planning study work with renewable integration studies performed by the ISO for the CPUC long-term procurement proceeding to determine whether policy-driven transmission facilities are needed to integrate renewable generation, as described in tariff section 24.4.6.6(g);
- reassesses, as needed, significant transmission facilities starting with the 2011-2012 planning cycle that were in GIP phase 2 cluster studies to determine — from a comprehensive planning perspective — whether any of these facilities should be enhanced or otherwise modified to more effectively or efficiently meet overall planning needs;
- performs a "least regrets" analysis of potential policy-driven solutions to identify those elements that should be approved as category 1 transmission elements,[2] which is based on balancing the two objectives of minimizing the risk of constructing under-utilized transmission capacity while ensuring that transmission needed to meet policy goals is built in a timely manner;
- identifies additional category 2 policy-driven potential transmission facilities that may be needed to achieve the relevant policy requirements and directives, but for which final approval is dependent on future developments and should therefore be deferred for reconsideration in a later planning cycle;
- performs economic studies, after the reliability projects and policy-driven solutions have been identified, to identify economically beneficial transmission solutions to be included in the final comprehensive transmission plan;

[2] In accordance with the least regrets principle, the transmission plan may designate both category 1 and category 2 policy-driven solutions. The use of these categories better enable the ISO to plan transmission to meet relevant state or federal policy objectives within the context of considerable uncertainty regarding which grid areas will ultimately realize the most new resource development and other key factors that materially affect the determination of what transmission is needed. The criteria to be used for this evaluation are identified in section 24.4.6.6 of the revised tariff.

- performs technical studies to assess the reliability impacts of new environmental policies such as new restrictions on the use of coastal and estuarine waters for power plant cooling, which is commonly referred to as once through cooling and AB 1318 legislative requirements for ISO studies on the electrical system reliability needs of the South Coast Air Basin;
- conducts stakeholder meetings and provides public comment opportunities at key points during phase 2; and
- consolidates the results of the above activities to formulate a final, annual comprehensive transmission plan to post in draft form for stakeholder review and comment at the end of January and present to the Board for approval at the conclusion of phase 2 in March.

When the Board approves the comprehensive transmission plan at the end of phase 2, its approval constitutes a finding of need and an authorization to develop the reliability-driven facilities, category 1 policy-driven facilities and the economically driven facilities in the plan. The Board's approval authorizes implementation and enables cost recovery through ISO transmission rates of those transmission projects included in the plan that require Board approval under current tariff provisions.[3] As indicated above, the ISO will solicit and accept proposals in phase 3 from all interested project sponsors to build and own the transmission solutions that are open to competition.

Phase 3 will take place after the approval of the plan by the Board, if projects eligible for competitive solicitation were approved by the Board in the draft plan at the end of phase 2. Projects eligible for competitive solicitation are reliability-driven, category 1 policy-driven or economically driven elements, excluding projects that are modifications to existing facilities or local transmission facilities.[4]

If transmission solutions eligible for competitive solicitation are identified in phase 2 and approved, phase 3 will start with the ISO opening a project submission window for the entities who propose to sponsor the facilities. The ISO will then evaluate the proposals and, if there are multiple qualified project sponsors seeking to finance, build and own the same facilities, the ISO will select the project sponsor by conducting a comparative evaluation using tariff selection criteria. Single proposed project sponsors who meet the qualification criteria can move forward to project permitting and siting.

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[3] Under existing tariff provisions, ISO management can approve transmission projects with capital costs equal to or less than $50 million. Such projects are included in the comprehensive plan as pre-approved by ISO management and not requiring further Board approval.

[4] The description of transmission solutions eligible for the competitive solicitation process was modified as part of the ISO's initial Order 1000 compliance filing. It was accepted by FERC in an April 18, 2013 order and became effective on October 1, 2013 as part of the 2013-2014 transmission planning process. Further tariff modifications were submitted on August 20, 2013 in response to the April 18, 2013 order and a final ruling March 20, 2014.

2. Quantifying Benefits

2.1 Updated benefit framework

TEAM provides a standard for measuring transmission expansion benefits for consumers, producers, and transmission owners. While the original methodology explored a range of perspectives, the "ratepayer" perspective has been relied upon consistently since the methodology was introduced. Other options that had been considered initially and subsequently discarded were society and participant perspectives. However, WECC societal benefit perspective is used as well in order to assess if there is any impact on the system level of the entire WECC system.

TEAM original document focused on production benefit assessment based on production cost simulation. Additional benefits were discussed, but lacked details of implementation due to data and modeling limitations at the time when TEAM was introduced. In the current ISO's planning practice, additional benefits can be included.

In this chapter, benefit framework and the methods of quantifying benefits are presented in the context of production benefit first, followed by the discussion of additional benefits and their assessment methodologies.

2.2 Welfare Measures in Electricity Wholesale Markets

2.2.1 Define Market and Relevant Market Participants

Because of the interconnected nature of the Western electricity system, the relevant geographic area for a transmission expansion project sited primarily in the CAISO controlled area could be much broader than the CAISO control area itself. Full network model for the entire Western electricity system is used in the ISO's economic planning study.

Classical economic surplus measures are used to define the welfare of all participants in the electricity wholesale market.[5] In the electricity wholesale market, participants involved with physical production, transport, and use of electricity may be buyers (i.e., consumers), sellers (i.e., generators), and facilitators (i.e., transmission owners).[6] Consumers are often represented by their electricity distribution companies (public utilities) that purchase power to meet residential and commercial customers' load. The cost of operating such public

[5] As previously mentioned, economic benefits of reliability changes are not the main focus of this methodology.
[6] There are other market participants as well, such as the marketers/traders, but they do not necessarily handle the physical supply, transport, or consumption.

utilities (i.e., revenue requirement) is often recovered through regulated customer rates. Sellers are electricity generators including both merchant generators and utility-owned generators. Merchant generators are usually un- regulated, selling power for profit. Utility-owned generation is often used to meet the utility's own native load. Revenues from utility-owned generation from power sales surplus to its own customers' needs usually offset the utility's regulated revenue requirement.

As noted above, there are two types of transmission owners – merchant (or private or independent) transmission owner and regulated Participating Transmission Owners (PTOs). The cost of transmission investment for a PTO is rolled into the CAISO's PTO Transmission Revenue Requirements Balancing Account and charged as a Transmission Access Charge (TAC) to the load. Thus the regulated investment cost of a transmission upgrade can be recovered through a regulated customer rate. The private investment cost of a merchant transmission upgrade is often recovered by receiving Congestion Revenue Rights (CRRs) for the incremental transmission capacity resulting from an upgrade[7]. In this case, the merchant transmission will receive no payment other than the FTR or CRR revenues allocated to it.

The distinction between private investment and regulated investment is important because it determines who pays for such investment and whose benefits should be considered in transmission expansion cost-benefit analysis. We believe the key elements of any economically driven transmission investment decision are identifying potential beneficiaries of the investment, quantifying all benefits to the transmission funding participants, and comparing expected benefits of a transmission investment against its cost under a wide range of future system conditions. If a transmission upgrade project is ratepayer funded and the cost will be recovered through regulated cost sharing, the regulatory authorities have to identify exactly who those ratepayers are and how much they benefit. If a project is a merchant transmission investment and the cost will not be recovered by regulated rates, then the merchant transmission company needs to make sure the project meets their financial goals. The CAISO (or any other entities responsible for transmission expansion coordination) has to make sure such project does not jeopardize the stability and reliability of the controlled grid. Although the CAISO's focus is on regulated transmission investment, this methodology is general enough that any market participant can use it to evaluate the effectiveness of its project.

2.2.2 Define Market Participants' Surplus Components

Consumer Surplus

Consumer surplus is the difference between what consumers are willing to pay for a product versus what they actually pay. In an energy market, a consumers' willingness to pay can be measured by Value of Lost Load (VOLL). This measure indicates the approximate value of avoiding involuntary energy curtailments.

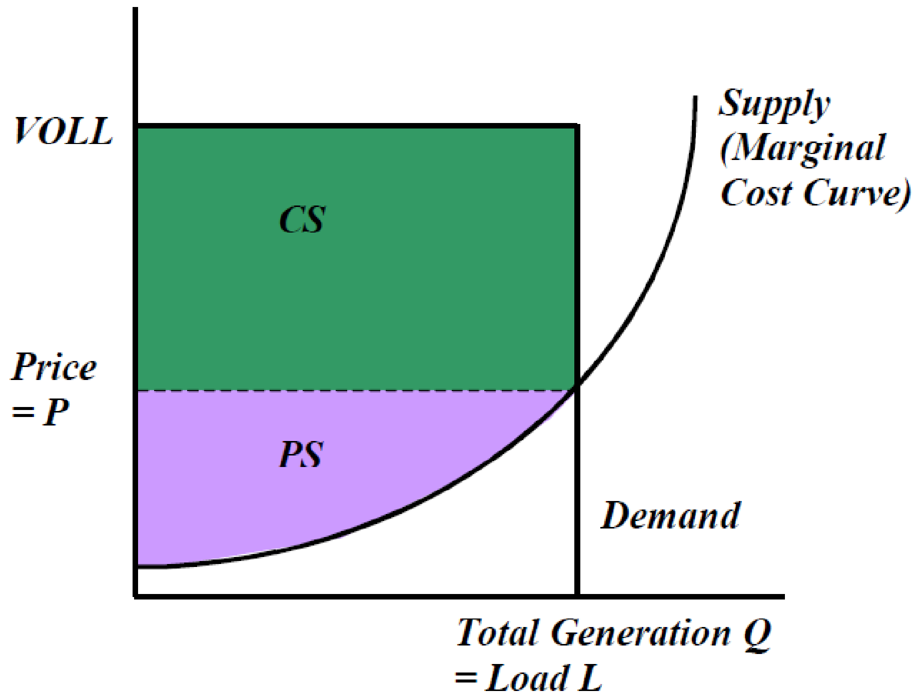

Figure 2.1: Consumer and Producer Surplus

Figure 2.1 graphically depicts consumer and producer surplus under the simple case of an un-congested system where prices are the same across the whole network and all generators bid their marginal costs. The example also assumes that demand is perfectly inelastic and there are no transmission losses or wheeling charges.[7] The green rectangle area marked as CS denotes consumers' surplus. It can be computed as

$$CS = (VOLL - Price) \cdot Load = VOLL \ \cdot L - CTL$$

where VOLL is Value of Lost Load, L is total load (equal to total generation in this case), and CTL is total Cost-to-Load. If there is congestion in the system, prices will differ by location. However, consumer surplus can be still computed in the same fashion by multiplying load by the price load pays and summing it up for the appropriate geographic region and time horizon. The total WECC consumer surplus is the sum of each region's consumer surplus. Each region's annual cost-to-load is computed as the following:

$$CTL_{i,t} = P_{i,t} \cdot L_{i,t}$$

where *i* (= 1, 2, 3, …, 21) is the *i*th region in WECC area, *t* (= 1, 2, …, 8760) is the *t*th hour per year, and $P_{i,t}$ is quantity-weighted average Locational Marginal Price (LMP) in region *i*

[7] The CAISO methodology can be generalized to account for price elastic demand. As demand- response programs based on real-time pricing become more important, such an enhancement should be investigated.

at hour *t* and $L_{i,t}$ is total load in region *i* at hour *t*. Thus the total WECC consumer surplus summed over all 21 WECC regions is

$$WECC\ CS_t = \sum_{i=1}^{t} \left[VOLL \cdot L_{i,t} - CTL_{i,t}\right]$$

We assumed that the same VOLL applies to all loads in all regions. In practice, VOLL may be different for different categories of consumers, such as industrial, commercial, residential, etc. But the formula can be generalized if needed, to account for different VOLL levels for different regions and consumer classes. However, it is important to note that in the end, we are interested in capturing the change in consumer surplus resulting from a transmission upgrade. If there is no change in reliability (i.e., the total amount of load is served), then when calculating the change in consumer surplus, all VOLL terms will cancel out. Therefore the value used for VOLL is immaterial in the end. The value of a project to improve the reliability of serving load will be evaluated separately as reliability benefit.

The definition of consumer surplus for the entire WECC area is subject to the following caveats. The WECC area outside of the CAISO controlled area does not currently have a central market and will likely not have one in the near future. As a result, there is no specific price at each load center or generation bus. Transactions are usually accomplished through bilateral agreements. Nevertheless, our defined calculation of consumer surplus indicates how much consumers will gain if the rest of WECC moves into a centralized wholesale market (or several markets). Furthermore, even with the current market structure we can still assume that through price discovery in California's energy market and trading hubs elsewhere in the WECC, the bilateral transaction prices throughout the WECC will over time converge in a "long-term expected value" sense to levels that would otherwise result from a seamless centralized WECC market.

Producer Surplus

Producer surplus is the difference between the total payment producers received (Producer Revenue, PR) and the total variable production cost (PC).

$$PS = PR - PC$$

In Figure 2.1, the purple area indicates total producer surplus in the whole system in the case of no congestion and inelastic demand. But when there is congestion in the system, generators may receive different locational prices. Nevertheless producer revenue can be still computed as output quantity multiplied by price received and summed to the appropriate geographic region.

The generation revenue is not only from the generation times LMP, but also can be from ancillary services. Therefore it is needed to add an item or multiple items to reflect AS revenues. On the other hand, emission cost and startup cost need to be counted as part of the total producer cost. The pumping cost of pumped storage station and pumping station, or the charging cost of battery storage, is also counted as part of the total producer cost. With generation G, price for generation P_G, ancillary service production AS, the corresponding price P_{AS} and VOM denoting variable operation and maintenance cost, producer surplus is

$$PS = G \cdot P_G + AS \cdot P_{AS} - VOM - Fuel\ Cost - Emission\ Cost - Start\ Cost - Pump\ Cost - AS\ Cost$$

Total WECC producer surplus is the sum of each region's producer surplus. Thus the total WECC producer surplus is

$$WECC\ PS_t = \sum_{i=1}^{21} PS_{i,t}$$

This definition of producer surplus for the outside CAISO area is also subject to the caveats previously discussed.

Congestion Revenue

As full network model has been used in production cost simulation, the shadow prices for all congested branches are available hence the congestion revenue for the congested branch is the product of it shadow price and the binding limit of the branch flow. Congestion revenues for interfaces and nomograms can be obtained with the same approach. With shadow price λ, and b,i,n denoting single branches, interfaces and nomograms, and with B,I,N denoting corresponding total number of branches, interfaces and nomograms, the equation is:

$$CR = \sum_{b=1}^{B} \lambda_b \cdot R_b + \sum_{i=1}^{I} \lambda_i \cdot R_i + \sum_{n=1}^{N} \lambda_n \cdot R_n$$

Total Social Surplus

Total surplus is the sum of consumer surplus, producer surplus, and congestion revenue.

$$TS = CS + PS + CR$$

We can compute total social surplus at both the WECC level and regional level.

2.2.3 Impact of Strategic Bidding on Surpluses

It is recognized that market power can still exist and will allow participants who have the market power to use strategic bidding. However, market power mitigation process in a well-designed market environment would force such strategic bidding to be replaced with the participants' default bids, which normally are the marginal costs. Therefore, strategic bidding is not used in the current ISO's economic planning study, in which all generators are assumed participating in the economic dispatch based on their variable cost.

2.3 The Impact of Transmission Expansion on Surpluses

The fundamental benefits of a transmission upgrade are to improve reliability and facilitate commerce; the latter category of benefits is the focus in this CAISO methodology. A transmission upgrade facilitates commerce by creating greater access to regional markets, which may result in greater access to lower cost supply and greater market competition. A transmission upgrade may expand the number of suppliers who can compete to supply energy at any location in a transmission network. With sufficient transmission capacity to all locations in a network, generators will face significant competition from multiple independent suppliers, which will reduce their financial incentive to bid above marginal cost since doing so would more likely result in their bids not being selected.

As we discussed above there are three categories of participants in the market: (1) consumers; (2) producers; and (3) transmission owners. If one wants to evaluate an upgrade, the benefits for all market participants must be considered and calculated, especially for those parties who will ultimately pay for the transmission upgrade. Since there are many ways to allocate the cost of a transmission investment, decision makers must evaluate all aspects of the benefit components. Moreover, the transmission valuation methodology must provide the building blocks necessary to evaluate the benefits of a variety of transmission projects. In the following sections, we discuss these benefit building blocks.

2.3.1 Societal Benefit

The fundamental economic impact of transmission upgrade is that it may make the system more efficient and thus lead to more efficient economic dispatch. Thus the societal benefit of a transmission upgrade can be measured as the reduction in total variable production cost of serving load (i.e. the production cost savings).[8] Let $PC_{w/o}$ denote a system's total variable production cost without an expansion project, and let PC_w denote the total variable production cost with the expansion. Then the total societal benefit (SB) is:[9]

$$SB = PC_{w/o} - PC_w$$

It is easy to determine whether a transmission upgrade project is beneficial or not from the societal point of view. However, not all market participants benefit when additional transmission is built to relieve congestion. It is important to quantify who benefits from expansion and who does not. Furthermore, total societal benefit, as measured in total variable production cost savings, can be further disaggregated into three components across regions:

[8] Note that this situation holds only when demand is perfectly inelastic (i.e., zero price elasticity). If demand is not perfectly inelastic, this statement needs to be modified to reflect the substitution effect between price and quantity.
[9] In the presence of price elastic demand, welfare is instead equal to total surplus, equal to total consumer willingness to pay for the electricity consumed minus the cost of providing it. The CAISO methodology does not presently consider elastic demand.

- Consumer benefit from upgrade
- Producer benefit from upgrade
- Transmission owner benefit

The following sections discuss each component in more detail.

2.3.2 Consumer Benefit, Producer Benefit, and Transmission Owner Benefit

In a two-zone model, let Zone 1 and Zone 2 be connected by a transmission line with capacity T. Suppose we plan to expand the line limit to T + ΔT and would like to measure the benefit due to this expansion. The line may still be congested after expansion. With the transmission expansion, it is likely that generators in Zone 1 will produce less output and generators in Zone 2 will produce more output than they would without expansion. It is also likely that the Price in Zone 1 will be lower and price in Zone 2 will be higher compared to the no expansion case. In order to quantify the impact of transmission expansion on welfare, we need to:

- Compute all welfare measurements (i.e., all surpluses) for cases without and with expansion
- Subtract surplus without expansion from surplus with expansion
- Obtain the net impact of transmission expansion on surpluses

We call the change in surpluses caused by a transmission expansion the “transmission benefit”. Figure 2 shows how consumers and producers in each zone are benefited or harmed by a transmission upgrade in this two-zone example.

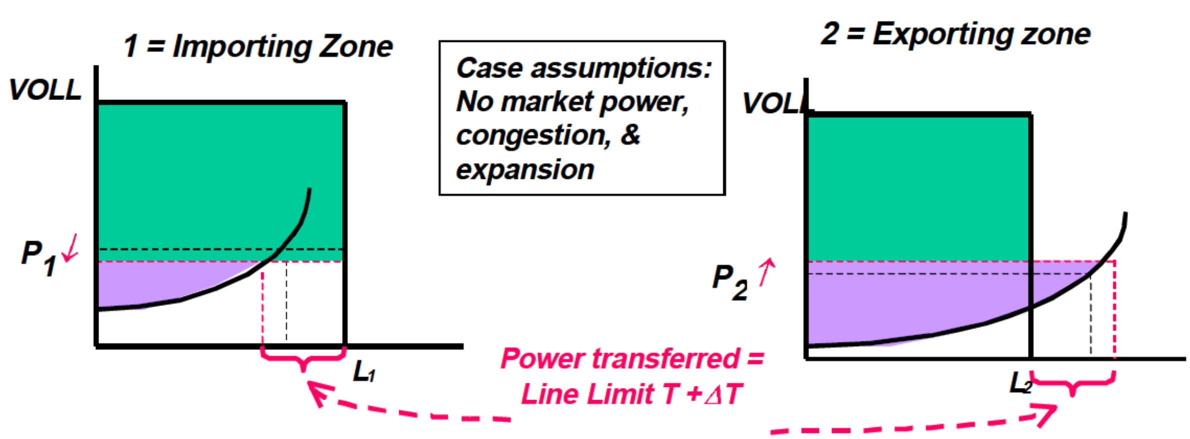

Figure 2.2: Transmission Benefit in the Two-Zone Example

If the amount of power transferred from Zone 2 to Zone 1 is increased, then consumers in Zone 1 may benefit from a lower price and consumers in Zone 2 may be harmed from a higher price.

$$\Delta CS_1 = -\Delta P_1 \cdot L_1 > 0$$

$$\Delta CS_2 = -\Delta P_2 \cdot L_2 < 0$$

However, producers in Zone 1 are harmed due to having less of their output dispatched and from receiving a lower price for their dispatch. On the other hand, producers in Zone 2 benefit from expansion due to having more of their output dispatched and from receiving a higher price for their dispatch.

$$\Delta PS_1 = \Delta PR_1 - PC_1 < 0$$

$$\Delta PS_2 = \Delta PR_2 - PC_2 > 0$$

Transmission owners of the line may or may not benefit from expansion depending how much the flow is increased and how much the price difference is changed.

$$\begin{aligned}\Delta CR = CR_w - CR_{w/o} &= (\Delta P_1 - \Delta P_2) \cdot T + \Delta T \cdot (P_{1w} - P_{2w}) \\ &= (P_{1w} - P_{2w}) \cdot T_w - \left(P_{1w/o} - P_{2w/o}\right) \cdot T_{w/o}\end{aligned}$$

If the line is no longer congested with expansion, TOs may have a net loss.

2.3.3 The Identity and Its Importance

The method of calculating consumer benefit, producer benefit, and congestion revenue benefit can be generalized from the simple two-zone model and applied to the complicated WECC network. One way to check the validity of the partitioning of total benefits among different market participants is to check whether the following identity holds at the system (i.e., WECC) level:

$$SB = -\Delta PC = \Delta CS + \Delta PS + \Delta CR$$

Our first step in benefit evaluation of any transmission project is to make sure the total societal benefit calculated can be correctly disaggregated into three major components: consumer benefit, producer benefit, and transmission owner benefit. If a transmission project's total societal benefits exceed its total project cost, the project is beneficial to the society as a whole. However, such a project may not benefit everybody, some market participants will benefit and some may not. Thus it is important to further examine the distributional impacts of a transmission project on the various market entities. In the next section we will present our economically driven transmission expansion evaluation criteria and discuss various different perspectives.

2.4 Economically Driven Transmission Evaluation Criteria

2.4.1 Cost-benefit framework

We use a traditional cost-benefit framework in deciding whether a proposed project is desirable from varying welfare perspectives. In theory, the optimal investment rule requires that for investment, the evaluator should make sure that each candidate investment satisfies a two-part test, namely

- A project's net present value (NPV), with benefits and costs over the project's lifetime factored into the calculation that exceeds zero. With subscript t = 1, 2, …, T, representing the years during the planning period, d, representing the discount rate for benefit and cost calculation, and B and C, representing benefits and costs,[10] this can be expressed as

$$NPV = \sum_{t=0}^{T} \left(\frac{B_t}{(1+d)^t} - \frac{C_t}{(1+d)^t} \right) > 0$$

  The NPV criterion is also can be replaced equivalently with the Benefit-Cost-Ratio (BCR) criterion

$$BCR = \frac{\sum_{t=0}^{T} \left(\frac{B_t}{(1+d)^t} \right)}{\sum_{t=0}^{T} \left(\frac{C_t}{(1+d)^t} \right)} > 1$$

- The project selected has the highest NPV or the highest BCR

  As a practical matter, the second part of the test, which is for the cost, is often narrowly done by reviewing a limited number of alternatives (alternative timing, alternative transmission project, alternative generation project, or demand-side management projects). Thus the main focus is on the NPV calculation and testing.

The NPV of a transmission upgrade may also hinge on who will ultimately bear the cost of the project. Depending on who ultimately funds the transmission project the applied discount rate could be different. For instance, if the transmission project is funded by CAISO ratepayers then a social discount rate or a regulated discount rate should be applied. However, if an independent merchant entity funds the project, a private discount rate should be applied. What should be included in the benefit and cost calculation depends on who ultimately funds the project and who benefits from the project. Fundamentally, net benefits should be the summation of the benefits for all market participants who pay for the project less their costs. Since most projects will enhance the welfare of some market participants

[10] Here, the Bs are the expected benefits of the project calculated considering a wide range system conditions. In Chapter 5 we will discuss how we weight each scenario to calculate the expected benefit.

while diminishing the welfare of others, a project's acceptability should be judged based on the impact in aggregate.

The annual costs of a transmission project should be evaluated against the estimated annual revenue that a transmission owner would require to undertake the project. The total revenue requirement instead of the capital cost of a project is used as the cost of the project to be compared with its benefit. The details of total revenue requirement are discussed in Appendix A.

In the CAISO's economic planning, 5-year and 10-year studies are conducted to get the benefits for these two years. The benefits for the years between the 5-year and 10-year are estimated through linear interpolation. Beyond 10 years, the benefits are assumed to be flat at the same value as the 10-year's benefit. Then the NPVs at the in-service year of the project are calculated for each year through the life time of the project. The total benefit is the summation of the NPVs of every year.

2.4.2 WECC Societal Perspective

The societal perspective focuses on the overall benefit across the entire Western Interconnection. It looks at the societal benefit of a transmission project at a system-wide level with all relevant regions and relevant market participants included. Given that western systems are all inter-connected, a significant transmission project can pass the societal test if the WECC region as a whole benefits from the project. Furthermore, the societal benefit to the WECC region from a transmission project can be measured as the reduction in total WECC variable production cost of energy:

$$SB_{WECC} = -\Delta PC_{WECC}$$

If everyone is part of the unified market, costs of new transmission can be spread across all users of the transmission system and the unified market could be the vehicle through which costs are recovered from all users.

2.4.3 CAISO ratepayer perspective

The CAISO ratepayers are defined as all parties that are responsible for contributing to the transmission revenue requirement balance account for the CAISO Participating Transmission Owners (PTOs). Utility-retained generation is also included in the CAISO ratepayer perspective since profits (or negative profits) from this generation flow into the balance account. Furthermore, transmission owners of the CAISO controlled grid, which are acting as agents for the final ratepayers (i.e. retail consumers within the CAISO controlled grid), are also included in the CAISO ratepayers since their congestion revenues flow into the balance account.

The CAISO ratepayer test focuses on the benefits that would accrue to those entities funding the upgrade. The CAISO ratepayers' production benefit from transmission upgrade can be calculated as the difference of net load payment between the cases pre and post project.

Generally, net load payment can be calculated as

Net load payment *= ISO's Gross load payment – ISO's Generator profit – ISO's Transmission revenue*

Gross load payment *=* $\sum$*(Load X LMP)*

Generator profit *=*$\sum$*(Generator revenue – Generator cost)*

Transmission revenue *=* $\sum$*(Congestion cost + wheeling cost)*

Ownership is used to indicate which transmission's revenue and generator's profit will be counted to offset ratepayer's payment, and usually defined as ISO "owned" in the ISO's production cost model

"Owned facilities" operated to the ISO ratepayer advantage include

- PTO owned transmission
- Generators owned by the utilities serving ISO's load
- Wind and Solar under contract with an ISO load serving entity to meet the state renewable energy goal
- Other generators under contracts of which the information is available for public may be reviewed for consideration of the type and the length of contract

2.4.4 Perspective Used in the ISO's Planning Process

Cost covering of transmission upgrades is collected from the ratepayers by the TAC. Thus, the ratepayer perspective best reflects the regulatory framework and is the prevailing perspective used in the economic evaluation of transmission upgrades. However, the WECC societal benefit perspective is used as well in order to assess the impact on a system level. This perspective is especially important for projects with obvious interregional impacts.

2.5 Additional benefits of economically driven transmission expansion

In this updated document, the benefit framework of TEAM is expanded to other benefits, which are discussed in the following sections. The criteria and perspectives for benefit calculation discussed above for production benefit apply to all categories of benefits, although the specific benefit assessments use different approaches.

It is worth noting that for a specific project there may be only some types of these additional benefits applicable, and it should be case by case based and would be depending on numbers of factors such as the location of the project, the type of upgrade, etc.

2.5.1 Resource adequacy benefit from incremental importing capability

A transmission upgrade can provide RA benefit when the following four conditions are satisfied simultaneously:

- The upgrade increases the import capability into the CAISO's controlled grid in the study years.
- There is capacity shortfall from RA perspective in CAISO BAA in the study years and beyond.
- The existing import capability has been fully utilized to meet RA requirement in the CAISO BAA in the study years.
- The capacity cost in the CAISO BAA is greater than in other BAAs to which the new transmission connects.

Reliability assessment, which includes power flow and stability studies, is needed in order to assess the RA benefit. The peak load condition is studied to identify the incremental capacity on the import into the ISO's controlled grid with the transmission upgrade modeled. If all above four conditions are satisfied, the RA capacity is calculated as below:

RA benefit = Incremental capacity * (Cost of the marginal unit in RA procurement at the receiving end – Cost of the marginal unit in RA procurement at the sending end)

Given the current market design and data availability, the cost of the marginal unit in RA procurement in the ISO's controlled grid can be approximated with the per MW investment cost of gas turbine units that will be built inside ISO's controlled grid. The cost of the marginal unit in RA procurement in the sending end will depend on whether there will be capacity deficiency in the areas at the sending end. If there is deficiency in the sending area, then the cost can be approximated similarly with the per MW investment cost of gas turbine units. Otherwise, the actual RA procurement marginal cost at the sending end will be used.

2.5.2 Transmission loss saving benefit

Transmission upgrade may reduce transmission losses. The reduction of transmission losses will save energy hence increase the production benefit for the upgrade, which is incorporated into the production cost simulation with full network model. In the meantime, the reduction of transmission losses may also introduce capacity benefit in a system that potentially has capacity deficit.

Using production cost modeling, the capacity benefit from the transmission loss saving can be assessed in two ways. One is to reduce the peak demand so that the need for generation capacity in the peak hours would reduce. The other way is to increase the net qualified capacity for the existing generation resources.

2.5.3 Deliverability benefit

Transmission upgrade can potentially increase generator deliverability to the region under study through the directly increased transmission capacity or the transmission loss saving. Similarly to the resource adequacy benefit as described in Section 3.5.1, such deliverability benefit can only be materialized when there will be capacity deficit in the region under study. Full assessment for assessing the deliverability benefit will be on case by case basis.

2.5.4 LCR benefit

Some projects would provide local reliability benefits that otherwise would have to be purchased through LCR contracts. The Load Serving Entities (LSE) in the CAISO controlled grid pay an annual fixed payment to the unit owner in exchange for the option to call upon the unit (if it is available) to meet local reliability needs. LCR units are used for both local reliability and local market power mitigation. LCR benefit is assessed outside the production cost simulation. This assessment requires LCR studies for scenarios with and without the transmission upgrades in order to compare the LCR costs. It needs to consider the difference between the worst constraint without the upgrade and the next worst constraint with the upgrade. The benefit of the proposed transmission upgrade is the difference between the LCR requirement with and without the upgrade.

2.5.5 Public-policy benefit

If a transmission project increases the importing capability into the CAISO controlled grid, it potentially can help to reduce the cost of reaching renewable energy targets by facilitating the integration of lower cost renewable resources located in remote areas.

When there is a lot of curtailment of renewable generation, extra renewable generators would be built or procured to meet the goal of renewable portfolio standards (RPS). The cost of meeting the RPS goal will increase because of that. By reducing the curtailment of renewable generation, the cost of meeting the RPS goal will be reduced. This part of cost saving from avoiding over-build can be categorized as public-policy benefit.

2.5.6 Renewable integration benefit

As the renewable penetration increases, it becomes challenging to integrate renewable generation. Interregional coordination would help mitigating integration problems, such as over-supply and curtailment, by allowing sharing energy and ancillary services (A/S) among multiple BAAs.

A transmission upgrade that increases the importing and exporting capability of BAAs will facilitate sharing energy among BAAs, so that the potential over-supply and renewable curtailment problems within a single BAA can be relieved by exporting energy to other BAAs, whichever can or need to import energy.

A transmission upgrade that creates a new tie or increase the capacity of the existing tie between two areas will also facilitate sharing A/S Sharing between the areas, if the market design allow sharing A/S. The total A/S requirement for the combined areas may reduce when it is allowed to share A/S. The lower the A/S requirement may help relieving over-supply issue and curtailment of renewable resources.

It is worth noting that allowing exporting energy, sharing A/S, and reduced amount of A/S requirement will change the unit commitment and economic dispatch. The net payment of the CAISO's ratepayers and the benefit because of a transmission upgrade will be changed thereafter. However, such type of benefit can be captured by the production cost simulation and will not be considered as a part of renewable integration benefit.

2.5.7 Avoided cost of other projects

If a reliability or policy project can be avoided because of the economic project under study, then the avoided cost contribute to the benefit of the economic project. Full assessment of the benefit from avoided cost is on a case-by-case basis.

3. Production Cost Simulation using Full Network Model

In order to perform a correct economic assessment of an upgrade, the actual physical impact of the upgrade has to be modeled correctly. Accurate physical transmission modeling is also important to ensure that reliability and delivery standards are achieved. Since these standards are based on physical line flows, a full network model is implemented, satisfying the following requirements:

Table 3-2: Production Cost Simulation Requirements Relating to the Network Model Requirement

No	Requireme
1	Must use a network model that is derived from a WECC power flow case.
2	Performs either a DC or AC OPF that correctly models the physical power flows on transmission facilities for each specific hourly load and generation pattern.
3	Capable of modeling and enforcing individual facility limits, linear nomograms, and path limits.
4	Capable of modeling limits that vary based on variables such as area load, facility loading, or generation availability.
5	Capable of modeling transmission limits
6	Models phase shifters, DC lines, and other significant controllable devices
7	Capable of calculating nodal prices.
8	Capable of plotting the hourly flows (either chronologically or by magnitude) on individual facilities, paths, or nomograms.
9	While not required, it is desirable for the simulations to model transmission losses.

Production cost simulation is performed using DC power flow and least cost dispatch to simulate system operations in 8760 hours in a year. The simulation uses a full network model and computes locational marginal prices for every node, consisting of the short run marginal cost of energy, the marginal cost of congestion and the marginal cost of losses. The data used are usually developed on the basis of one of the TEPPC Common Cases. They contain operation and maintenance costs, fuel costs, CO_2 costs as well as basic technical parameters, such as efficiency, emission rates and ramp up and down rates, among others. The full network model is included in the TEPPC cases as well.

Production cost simulation based on full network model also considers other market and grid operation in the future years, such as ancillary services (A/S) and the hurdle rates among balancing authority areas (BAA), and potentially the energy imbalance market (EIM). The details of these market and grid modeling are discussed in Appendix B and Appendix C.

4. Modeling Prices

Modeling the underlying prices is the basis for any economic assessment. A new transmission project can enhance market competitiveness by both increasing the total supply that can be delivered to consumers and the number of suppliers that are available to serve load. In a liberalized electricity market, suppliers are likely to optimize their bidding strategies in response to such changing system conditions or observed changes in the behavior of other market participants. Theoretically, strategic bidding can be modeled using game theoretic or empirical approaches.

However, in the long term, no generator can operate below its short run marginal cost. Furthermore, the current market design performs market power mitigation. Additionally, strategic bidding is closely related to the location and technology of certain generators. Due to the long-term horizon of transmission planning, the existence of these circumstances favoring strategic bidding is uncertain. This uncertainty is assumed to be greater than the added value of including strategic bidding in the analysis.

As a consequence, in the ISO's current economic planning studies, cost-based production cost simulation is used.

5. Sensitivity Case Selection

Decisions on whether to build new transmission are complicated by risks and uncertainties about the future. Future load growth, fuel costs, and availability of hydro resources are among some of the many factors impacting decision makers. Some of these risks and uncertainties can be easily measured and quantified, and some cannot.

It is needed to consider risk and uncertainty in economic transmission planning. In order to do so, sensitivity studies would be needed to test the robustness of the economic assessment results. Different from the original TEAM document, in which a stochastic approach was proposed to select sensitivities, the current economic planning practice in the CASIO takes a practical approach to study some or all of the following sensitivities depending on the data availability and the specific need of the project under evaluation:

Table 5-1: Typical sensitivity analyses

Sensitivity analyses	Note and typical variation
Load - High	+6% above forecast
Load - Low	-6% below forecast
Hydro - High	if applicable and data available
Hydro - Low	if applicable and data available
Natural gas prices - High	+50%
Natural gas prices - Low	-25%
CA RPS portfolios	If data available
Other sensitivities per requested	

6. Summary

TEAM provided principles and a framework for economic planning studies. Implementations of TEAM principles have changed as the environment changes. This updated document provides a summary of the application of TEAM in ISO's economic planning practices and the corresponding updates in the TEAM implementation.

While the Implementation has been updated to reflect the changes on market and grid operation, and planning processes, the framework of TEAM remains the same. In the current ISO's practice and in this updated document, ISO "ratepayer's" perspective is the perspective relied upon for benefit calculations, as the ratepayers are ultimately funding the development through rates. In addition to production benefit, assessment of other benefits have been added to the TEAM framework.

Other updates include:

- Enhanced production cost model has been applied to reflect market and grid operation.
- Cost-based production cost simulation is used. Strategic bidding is no longer modeled.
- Uncertainty is considered by simulating pre-determined sensitivity scenarios by varying the most critical assumptions for the project under evaluation

With this documentation update, it is expected to set a consistent base for applying TEAM as process improvement, and also to set a more meaningful foundation for any future discussions.

Appendix A: Revenue requirement calculation and generic parameters for NPV of benefit and revenue requirement

The cost calculation for a transmission upgrade needs to be clarified depending on who proposed the upgrade and what process is taken. An upgrade can be proposed by the CAISO or by a transmission investor through request window.

If an upgrade needs to go through the solicitation process, the cost will be the actual revenue requirement of the project as the project sponsor proposed. For ISO proposed project, the revenue requirement is calculated based on the model and assumptions that are consistent with the CAISO Transmission Access Charge (TAC) model[11].

The parameters in the TAC model are summarized in Table A.1. The same social discount rate is used for calculating the NPV of benefit and revenue requirements. In the current studies, the discount rate is 7% (real).

Table A-1: Parameters for revenue requirement calculation in CAISO TAC model

Parameter	Value in TAC model
Debt Amount	50%
Equity Amount	50%
Debt Cost	6.0%
Equity Cost	11.0%
Federal Income Tax Rate	35.00%
State Income Tax Rate	8.84%
O&M	2.0%
O&M Escalation	2.0%
Yeas of depreciation	15
Depreciation Rate	2.5%

[11] http://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=7A2CFF1E-E340-4D46-8F39-33398E100AE7

For general screening, per unit cost on the ISO website is used to estimate the capital cost, and the present value of the annual revenue requirement is estimated as 1.45 times of the capital.

Appendix B: Market and grid modeling

B.1 Hurdle rate

Hurdle rate is used to mimic the actual transaction hurdles between Balancing Authority Areas (BAA) or regions. Normally, hurdle rates include Transmission Access Charge (TAC); Grid management charge (GMC), and other frictions. Hurdle rates can be modeled as exporting hurdles (in most cases) or interface hurdles in production cost simulation.

Hurdle rates are normally implemented by adding an extra cost to generators contributing to the flow, and can be enforced on commitment or dispatch or both in production cost model.

B.2 Ancillary services

Ancillary services (A/S) are co-optimized with energy in the production cost simulation. The A/S that are considered are Regulation up/down, Load following up/down, spinning/non-spinning. Frequency response is modeled as an A/S.

A/S requirements for Regulation and Load Following need to be calculated separately based on the load and renewable modeling, in consistent with ISO's renewable integration process and methodology[12].

B.3 Transmission constraints

The production cost database reflects a nodal network representation of the western interconnection. Transmission limits were enforced on individual transmission lines, paths (i.e., flowgates) and nomograms.

The ISO made an important enhancement in expanding the modeling of transmission contingency constraints. the ISO modeled contingencies on multiple voltage levels (including voltage levels lower than 230 kV) in the California ISO transmission grid to make sure that in the event of losing one transmission facility (and sometimes multiple transmission facilities), the remaining transmission facilities would stay within their emergency limits. The contingencies that were modeled in the ISO's database mainly are the ones that identified as critical in the ISO's reliability assessments, local capacity

[12] https://www.caiso.com/Documents/Aug13_2014_InitialTestimony_ShuchengLiu_Phase1A_LTPP_R13-12-010.pdf+&cd=1&hl=en&ct=clnk&gl=us

requirement (LCR) studies, and generation interconnection (GIP) studies. While all N-1 and N-2 (common mode) contingencies were modeled to be enforced in both unit commitment and economic dispatch stages in production cost simulation, N-1-1 contingencies that included multiple transmission facilities that were not in common mode, were normally modeled to be enforced in the unit commitment stage only. This modeling approach reflected the system reliability need identified in the other planning studies in production cost simulation, and also considered the fact that the N-1-1 contingencies normally had lower probability to happen than other contingencies and that system adjustment is allowed between the two N-1 contingencies. In addition, transmission limits for some transmission lines in the California ISO transmission grid at lower voltage than 230 kV are enforced.

Scheduled outages and derates of transmission lines or paths also need to be considered either based on the ISO's historical data or the data provided by the facility owners. Normally only the outages and derates that may produce routine congestion are considered as the baseline assumption.

Appendix C: EIM Modeling

Since 2014 several utilities outside of the CAISO's control grid have joint the CAISO's Energy Imbalance Market (EIM). By the market rule, EIM is the energy imbalance market in 15 minutes to 5 minutes time frame. The difference for the energy transactions in EIM and in the hour-ahead or day-ahead market is that the energy transaction across the boundary of BAAs in EIM is not subject to the wheeling charge.

With and without EIM modeled in the production cost simulation would impact the economic assessment results for transmission upgrades, and the economic justification may be alternated. Mainly due to the relative ease for entities to exit EIM and the long life of transmission assets, it is not recommended to consider the full effect of EIM in project justification. Particularly,

1. If a transmission upgrade is within the CAISO's control grid, or is seeking full funding by CAISO's ratepayers through transmission access charge, which is deemed an internal project financially, then the base case for economic assessment will be the one without EIM modeled. Meanwhile, there will be sensitivity studies with EIM modeled to test if the EIM has any impact on the economic benefit. The purpose of doing this is to avoid putting CAISO's ratepayers on risk if a transmission upgrade can only be justified economical with EIM modeled.
2. If a transmission upgrade is an inter-regional project that may benefit multiple planning regions' ratepayers or is seeking financial commitment from different regions, using with EIM or without EIM model as the base of the economic assessment will be case by case depending on the arrangement of cost sharing of the project between planning regions.

CAISO's EIM tariff can be used as the guidance of modeling EIM in the production cost simulation when the EIM effect needs to be considered in economic planning. Particularly:

1. Per CAISO Tariff Section 29.26.(a).(2) "Wheeling Access Charge. EIM Transfers from the CAISO Controlled Grid to another EIM Entity Balancing Authority Area using the contractual or ownership rights of an EIM Entity shall not constitute Wheeling Out and shall not be subject to the Wheeling Access Charge under Section 26."
2. Per CAISO Tariff Section 29.34.(m).(1) "Each EIM Entity Balancing Authority Area and the CAISO Balancing Authority Area will be responsible for meeting its own portion of the combined Flexible Ramping Constraint capacity requirements for the next hour as determined by Section 29.34(m)."
3. Per CAISO Tariff Section 29.34.(m).(5) "The CAISO shall determine the Flexible Ramping Constraint capacity requirement for all possible combinations of sufficient Balancing Authority Areas in the EIM Area, including requirements for individual

Balancing Authority Areas in each combination, by reducing the total Flexible Ramping Constraint capacity requirement for each group of Balancing Authority Areas by the total amount of EIM Internal Intertie import capability to that group from each Balancing Authority Area outside the group.

A proxy approach has been used in some production cost simulations for variety of studies in order to reflect the impact of EIM on generation dispatch:

- Define a group of EIM BAAs
- Assign a discount to the export wheeling charge rate for each of all EIM BAAs
- The discounted wheeling charge rates are applied to the generators in any of the EIM BAAs, and the generators in non-EIM BAAs are still subject to the full wheeling charge rates
- Allow sharing flexible ramping between EIM BAAs
    - Calculate standalone requirements for all BAAs
    - Calculate combined requirements
    - Calculate requirements in EIM:

      Req. in EIM = Standalone Req. * Combined Req. / sum of Standalone Req.

For the wheeling charge rates within the current CAISO EIM, the relative size of real time market to the day ahead market in terms of dollar value was recommended. For example, according to the Benefit report of PacifiCorp and California ISO Integration13 the energy cost in day-ahead market was about 93~96% of the total energy cost. In the current economic planning studies, it was assumed the day-ahead energy cost is 95% of the total energy cost. The discount to the export wheeling charge rates for EIM BAAs hence was 5%.

[13] https://www.caiso.com/Documents/StudyBenefits-PacifiCorp-ISOIntegration.pdf.