Aliso Canyon Gas-Electric Coordination

Phase 3

Draft Final Proposal

June 22, 2017

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Introduction

The purpose of this initiative is to mitigate continued risks to electric reliability due to constrained natural gas systems. Under the previous Aliso Canyon Gas-Electric Coordination Initiatives conducted in spring and fall 2016, the ISO identified there was a need to enhance its market and operational tools to increase gas-electric coordination to address reliability risks caused by the limited operability of the Aliso Canyon natural gas storage facility. The market and operational tools introduced to the ISO market on a temporary basis will expire on November 30, 2017.

Because the Aliso Canyon natural gas storage facility is expected to have limited operability for an extended period of time, the ISO (ISO) is proposing to extend the temporary market and operational tools currently in-place so that they remain in-effect beyond November 30. The ISO proposes to make market constraint limiting the maximum gas burn of a group of generators a permanent operational tool that can be used throughout the ISO and Energy Imbalance Market balancing areas. Experience over the past year has shown that the ISO has prudently used this tool and it has proven particularly effective when used. In combination with the natural gas constraint, the ISO proposes to make permanent its authority to deem transmission constraints uncompetitive when the natural gas constraint is enforced and to suspend convergence bidding when the constraint adversely impacts market efficiencies. The ISO also proposes to make the provisions to publish D+2 results permanent provisions. Finally, the ISO proposes to further temporarily extend other temporary market measures.

ISO proposes to temporarily extend the other temporary market measures because the long-term solutions to the need to balance gas-electric coordination issues through enhanced bidding rules addressed by these features are being evaluated under an existing stakeholder process, *Commitment Costs and Default Energy Bid Enhancements (CCDEBE)*[1]. The ISO believes that initiative is the appropriate format for proposing to enhance its cost based framework to reflect need to balance gas-electric system in a manner that supports system reliability. The CCDEBE enhancements are currently planned to be effective as of fall 2018. Consequently, the ISO proposes to extend these temporary measures until it implements these long-term changes.

This document describes the ISO's straw proposal for this third phase of the Aliso Canyon Gas-Electric Coordination policy initiative. The discussion in this paper is organized into the following sections:

- Background and Issue Discussion: Background discussion summarizing previous phases of this initiative including the source of concerns with gas-electric coordination and a procedural history of the Aliso Canyon stakeholder processes and filings.

- Proposal: Discussion of ISO's straw proposal to extend temporary market measures and to make the publication of D+2 advisory results and the maximum gas burn constraint and its accompanying measures a permanent operational tool. The section will first

[1] Stakeholder process documents available at: http://www.caiso.com/informed/Pages/StakeholderProcesses/CommitmentCosts_DefaultEnergyBidEnhancements.aspx.

discuss the proposal for operational and D+2 publication to be made permanent and then discuss the proposal for the other market measures to be extended temporarily.

- Plan for Stakeholder Engagement and Next Steps: Reviews ISO's plan for the stakeholder initiative targeting the July 2017 EIM Governing Body and ISO Board of Governors meetings. This section also includes a request for stakeholder comments on this straw proposal.

Summary of Stakeholder Comments

On gas constraints

ISO understood from stakeholder comments that there is general support for its proposal to make permanent the maximum gas burn constraint and extend authority to areas outside of Southern California. ISO understands that Portland General Electric (PGE), NV Energy (NVE), Puget Sound Energy (PSE), Pacific Gas & Electric (PG&E), and Southern California Edison (SCE), and the Department of Market Monitoring (DMM) support the ISO's straw proposal. These views were tempered by practical concerns. ISO understands that Western Power Trading Forum and NRG Energy oppose the proposal primarily for the following reasons (1) opposes extension until ISO completes comprehensive re-evaluation of bidding rules, (2) develops detailed, transparent guidelines for the gas constraint's associated measures, and (3) provide stronger support for extending measured beyond Southern California.

The ISO appreciated stakeholders tempering this support based on whether the ISO would continue to pursue long-term market enhancements to the bidding flexibility under *Commitment Costs and Default Energy Bid Enhancements*.

Portland General Electric (PGE) while conceptually supportive of ISO seeking this expanded, permanent authority, stated in their comments that the maximum gas burn constraint under this initiative is not going to solve more pressing problems not addressed here. PGE stated, "PGE's primary concern with this initiative is its potential to delay the work being done in the Commitment Costs and Default Energy Bid Enhancements (CCDEBE) initiative…the importance of this initiative should not be underestimated."

This sentiment was echoed by NRG Energy, Inc., Environmental Defense Fund, and Western Power Trading Forum. WPTF stressed that the maximum gas burn constraint is not a substitute for needing bidding rule changes, stating "ISO has not established that there is not a market based solution to their (assumed) reliability needs across the footprint…Adequate bidding rules should be a priority for the ISO and not be delayed because of this initiative." EDF characterized the need for long-term changes " a pressing need".

Further demonstrating general consensus among the stakeholder community, NRG Energy stated in their comments, "Given how little progress has been made with regards to consideration of changes to bidding rules, NRG opposes the CAISO making any of the temporary Aliso Canyon mitigation measures permanent until the CAISO completes the CC-DEBE process."

While the ISO stakeholders would like the CCDEBE initiative to proceed more rapidly, evaluating long-term market design changes such as those CCDEE is considering require careful collaboration with stakeholders. Given the complexity of policy development on bidding flexibility and cost recovery issues, the ISO believes that the existing schedule for the initiative to refine the design details with the stakeholders is reasonable.

CCDEBE's schedule was not significantly impacted by launching this final phase of Aliso Canyon and the ISO commits to continuing to prioritize its resources to the CCDEBE effort. The ISO is in part bringing the Aliso Canyon Gas-electric Coordination Phase 3 to the July board so that it can resolve the final phase of this effort and allow resources to primarily focus on CCDEBE and its November board for fall 2018 implementation.

Environmental Defense Fund (EDF) expressed concerns with tying the sunset date for the temporary market measures to the implementation of CCDEBE's measures due to the uncertainty around the CCDEBE timeline. EDF states, "This will create the impetus for reconsideration of the need for, and efficacy of, temporary Aliso measures, considering the then prevailing context." Given the ISO's commitment to allocating resources to the CCDEBE effort and bringing a proposal to the November Board of Governor's meeting and has a target date already reserved in the fall 2018 release, the ISO is confident that the CCDEBE features will be implementable in the near future. The ISO believes tying the sunset date to CCDEBE's implementation will allow for better planning and ensuring the measures retire as the long-term solutions become effective.

The ISO appreciated stakeholders communicating which areas of the proposal would benefit from more information and has endeavored to enhance the proposal sections accordingly.

Environmental Defense Fund, Western Power Trading Forum, expressed in their comments that insufficient justification was provided for the need to seek permanent authority to enforce a maximum gas burn constraint across the ISO footprint, including CAISO and EIM BAAs. The ISO has addressed these concerns in the Section titled, Make permanent gas constraint authority, and believes the explanations have provided greater transparency into the potential issues faced by ISO Operations balanced against need to maintain confidentiality with specific stakeholder business needs. Specifically to the request from EDF to provide "a detailed consideration of the results of the summer 2017 joint agency technical study", the ISO does not intend to elaborate on the findings it in collaboration with other agencies reached in the technical study. The fuller consideration can be found in those documents[2].

The ISO has addressed the DMM, NV Energy, PGE, and PG&E's requests for additional information on the design of the maximum gas burn constraint and the process for determining it would be enforced through enhancing the paper to include a background section on the ISO's gas-electric coordination including use of gas constraint, noting in the proposal section that the gas-electric coordination efforts described would be leveraged, and including a technical

[2] Mitigation measures document includes a fuller consideration of needs driving maintaining authority, available at http://www.energy.ca.gov/2017_energypolicy/documents/2017-05-22_workshop/2017-05-22_documents.php.

appendix with the details for the constraint. These details include the formulation, modelling approach used by the generation group nomogram technology for the purpose of reflecting maximum burn limits, guidelines for use, and how the gas resource will be settled.

For EIM specific questions posed by NV Energy and DMM, the ISO explains that it has assessed the impact on sufficiency, balancing and capacity tests in EIM and the role of EIM base schedules. The ISO explains these in the proposal and technical appendix sections. The ISO believes these additions are responsive to stakeholder requests and would accordingly enhance its business practice manuals to include these details.

On capturing gas constraint impact on mitigation

ISO understood from comments that PG&E, SCE, DMM, NV Energy, PSE, and PGE support the ISO proposal to permanently maintain its authority to ensure its mitigation measures reflect expected impacts to competition when maximum gas burn constraint is enforced. DMM requests the ISO fully automate the dynamic competitive path assessment as a more sustainable alternative to the existing manual process. PG&E supports DMM's suggestions for these enhancements.

SCE commented that it supports the notion proposed by the Department of Market Monitoring's comments that there is a need for appropriate mitigation related to incremental exceptional dispatches in its Phase 2 comments. The ISO after further discussion realized that the Department of Market Monitoring was not aware that the ISO had previously determined the authority to deem select transmission constraints uncompetitive should apply to the mitigation of incremental exceptional dispatches under its existing exceptional dispatch policy which says the dynamic competitive path assessment results (including overrides is implied) is used to determine . Consequently, the ISO included the detailed language in both its straw and draft final proposal that the override applies to both the dynamic and default assessments. The default assessment is used for exceptional dispatch mitigation. The ISO believes there has not been a "gap" on incremental exceptional dispatch since the authority has been in effect.

The Department of Market Monitoring submitted comments that the current manual approach for assessing whether a transmission constraint should be deemed uncompetitive is not sustainable in the long-term. DMM states, "the ISO needs to ensure that the automated calculations of supply of counterflow include impacts of gas nomograms." The ISO agrees that the manual process is not sustainable in the long-term. The ISO revised its proposal to propose automating the dynamic competitive path assessment to consider the maximum gas burn constraint as the full technology solution and will maintain the authority to override the current method to bridge to the full solution. The ISO will need to evaluate the workload associated with using the manual override while enforcing gas constraints in additional areas and may need to phase in implementing these constraints.

On transparency commitments

WPTF, EDF, PGE, PG&E, NV Energy, and DMM all seek greater levels of transparency. Some stakeholders are seeking the ISO affirm its commitment to continue providing sufficient levels of transparency for the maximum gas burn constraint and its accompanying measures.

The ISO commits to providing additional transparency around the authority to override the dynamic or default competitive path assessment or to suspend virtual bidding. The ISO commits to continuing to provide transparency around enforcing the maximum gas burn constraint and if it deems transmission paths uncompetitive at that time. The ISO releases a notification if a maximum gas burn constraint is enforced. If a manual override were to be issued, the ISO would notify the market at the time it enforced the constraint. Further, the ISO maintains its previous commitment to issue a technical bulletin with justifications for a general suspension or limitation of Virtual Bids if suspended using this authority.

On real-time gas commodity price scalars

DMM support continued use of real-time gas commodity price scalars when appropriate caveating that they "stress the need to lower levels when there is no evidence of a tight market." SCE's comments were supportive of these statements by the DMM stating, "the CAISO should be prepared to adjust the cost scalar adders as appropriately needed." The ISO agrees with both stakeholders that it is a critical component of the design that the ISO be able to raise or lower these scalars, which is why this flexibility is contained in the Tariff.

The ISO does not believe the specific level of the scalars is a policy discussion. There exists an internal business process for determining whether there is a need to adjust the scalars. The ISO will adjust the scalers if analysis shows it is appropriate and would issue a market notification communicating this decision.

Background and Issue Discussion

Procedural History

Under the *Aliso Canyon Gas Electric Coordination Measures* initiative Phase 1, the ISO launched an expedited stakeholder process to address operational concerns due to reliability risks identified in an inter-agency task force's technical report and action plan.[3] The ISO together with stakeholders designed eleven temporary measures which the ISO filed with the Federal Energy Regulatory Commission (FERC) for approval on May 9, 2016[4], to be effective through November 30, 2016. See the original Revised Draft Final Proposal for Aliso Canyon Gas-Electric Coordination for Phase 1 for background information and a description of each approved temporary measure[5]. FERC subsequently approved this filing effective June 1, 2016 through November 30, 2016[6].

Of the 11 measures filed under the Phase 1 filing, three measures were previously vetted and developed with stakeholders under the Bidding Rules Enhancements initiative as permanent

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[3] All the inter-agency materials are accessible through stakeholder webpage, http://www.caiso.com/informed/Pages/StakeholderProcesses/AlisoCanyonGasElectricCoordination.aspx
[4] http://www.caiso.com/Documents/May9_2016_TariffAmendment_EnhanceGas-ElectricCoordination_LimitedOperation_AlisoCanyonNaturalGasStorageFacility_ER16-1649.pdf
[5] http://www.caiso.com/Documents/RevisedDraftFinalProposal_AlisoCanyonGas_ElectricCoordination.pdf
[6]http://www.caiso.com/Documents/Jun1_2016_OrderAcceptingTariffRevisions_Establishing_TechnicalConference_AlisoCanyon_ER16-1649.pdf

market features. Consistent with the Board of Governors' approval of these measures, the ISO filed for approval to revise its tariff and make those bidding rules permanent on August 19, 2016.[7] FERC approved the three measures on November 21, 2016.

Under Phase 2, the ISO evaluated whether the eight remaining temporary measures enhancing gas-electric coordination should be extended in light of concerns with continued operational risks. The concerns were based on a revised reliability assessment for winter 2016/2017 from the same interagency task force, the Winter Action Plan and Winter Risk Technical Report, and whether the revised assessment warrants continuing the ISO's authority to utilize the eleven temporary measures designed to address operational concerns due to reliability risks.

The ISO did not propose to introduce new measures as the three new permanent provisions and the eight temporary measures previously approved were effective at managing natural gas system capacity limitations in addition to imbalance limitations.[8] The ISO determined two of the eight measures were not necessary to extend as the portfolio of measures without them was sufficiently robust. See the original Revised Draft Final Proposal for Aliso Canyon Gas-Electric Coordination for Phase 2[9] for background information and a description of each approved temporary measure. On October 14, 2016, the ISO filed to temporarily extend six measures to November 30, 2017. FERC approved the requested extension on November 28, 2016.

The inter-agency task force recently released the Aliso Canyon Risk Assessment Technical Report Summer 2017 Assessment.[10] The assessment states risks to electrical system reliability due to Aliso Canyon's limited operability are likely to continue. Consequently, the ISO is issuing this straw proposal to enable it to maintain the operational and market tools until the risks on the constrained gas system due to the limited operability of Aliso Canyon storage facility no longer pose a risk to reliable electric system operation.

Gas-electric coordination including use of gas constraint

ISO Operations is actively engaged in communicating with gas operations to coordinate operations supporting both systems. If through this coordination, the ISO identifies concerns that adverse operating condition may arise due to the upstream gas system it could select from a portfolio of operating tools to enforce a gas constraint.

The maximum gas burn constraint is one of the tools available to ISO operations to reflect anticipated limitations on the gas system so the market results will account for this limitation to avoid triggering reliability event (e.g. gas curtailments). ISO establishes guidelines and process

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[7] Bidding Rules and Commitment Costs Enhancements (ER16-2445) filing, available at http://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=1AA66AC3-C157-44C8-9B7C-384FD77C06D5.
[8] The Department of Market Monitoring has raised that there might be a need to mitigate exceptional dispatches related to the gas constraints under certain circumstances. The ISO and the Department of Market Monitoring continue to evaluate this issue and may later propose additional measures.
[9] Aliso Canyon Gas-electric Coordination Draft Final Proposal, available at http://www.caiso.com/Documents/DraftFinalProposal-AlisoCanyonGasElectricCoordinationPhase2.pdf.
[10] http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-11/TN217639_20170519T104800_Aliso_Canyon_Risk_Assessment_Technical_Report_Summer_2017_Asses.pdf

used to determine whether the operator should enforce a natural gas constraint. These processes are established with the gas company and documented in operating procedures.

Currently these procedures include addressing gas service area limitations or outages in Southern California and gas transmission pipeline derates or outages in the remainder of the ISO balancing authority area[11]. Through its coordination efforts, the ISO may identify the need to trigger one of these procedures to respond and appropriately operate the electric system while under adverse operating conditions.

The various coordination efforts span from advanced planning of pipeline or storage facility derates or outages through managing for anticipations of adverse conditions, specifically:

- Outage planning through bi-weekly calls with planners
- Under normal operations the ISO:
    - Provides D+2 and D+1 gas burn schedules
    - Holds daily calls on D+2 and D+1 gas burn schedules
    - Notifies if RT burns are higher than gas burn schedules
- Under peak day operations the ISO:
    - Issues flex alert or restricted maintenance operations
    - Holds peak day reliability call including gas companies, Peak RC, PTOs, and neighboring BAAs
    - Holds peak day market calls (all market participants)
- Under adverse operating conditions due to gas service area limitations the ISO:
    - Receives curtailment watch notification, where ISO can manage system using either gas constraints or exceptional dispatches
    - Receives curtailment instructions (i.e. transmission pipeline derates or outages) where ISO can manage system using either gas curtailment tool or exceptional dispatches
    - ISO will issue market notifications when action is taken

The procedure that could result in enforcing natural gas constraint in Southern California is found under the adverse operating conditions under its emergency operations procedures (Operating Procedure 4120c[12]). The procedure includes guidelines for addressing these adverse conditions such as:

- Scenarios under which the constraint could be enforced and actions by ISO, Scheduling Coordinator, or Gas Company etc.
- Relative timing of the coordination efforts
- Notifications associated with triggering the tool

Once Operations determines a need to enforce the constraint, the maximum gas burn constraint constrains the maximum amount of natural gas that can be burned by natural gas-fired

[11] Operating procedures 4120 and 4120c, available at http://www.caiso.com/Documents/4120.pdf and , http://www.caiso.com/Documents/4120C.pdf.
[12] Operating procedure available at, http://www.caiso.com/Documents/4120C.pdf.

resources, based on limitations, in applicable gas operating zones anticipated by the ISO[13]. The natural gas constraint permits ISO operators to enforce in the day-ahead and real-time markets a constraint(s) to limit the dispatch of generators in the affected areas to a maximum gas usage if there is a limitation on the maximum amount of gas used. The constraint(s) also limit the ISO market dispatch of the affected generators in the real-time market to a maximum gas usage if there is a limitation that relates to differences between gas scheduled with the gas company and gas consumed during the operating day due to gas system imbalance limitations. The constraint lowers the resource-specific locational marginal prices of gas generators subject to the constraint to ensure the necessary supply reduction occurs[14].

Although individual generators can manage their gas burn to comply with gas system constraints to a large extent through their ISO market bids, these bids from individual resources cannot completely ensure that the gas burn resulting from the ISO's overall dispatch in an area does not exceed the capacity of the gas system in that area especially under the existing bidding rules and cost estimate design. In some emergencies or situations that can lead to emergencies, the ISO may be required to take action to avoid burning gas in gas operating zones and cannot rely on bidding behavior alone to ensure reliable operations of the electric system.

Based on its experience using the gas burn constraint in southern California over the past year, the ISO has found this operational tool to be an important mechanism to avoid excessive impacts on the gas system under constrained gas system conditions to help keep the gas system within operational limits and avoid impacts to electric system reliability. Although the ISO has had to use the constraint sparingly, the ISO found the constraint to be a valuable operational tool to keep electrical generation gas usage within system constraints when it was used.

Specifically, the maximum gas burn constraint has proven to be effective for recognizing constraints on natural gas systems, when they arise, so that the ISO's dispatch solution does not exceed the system limits; system limits if not addressed through manual dispatch could undermine electrical reliability. The ISO has enforced the gas constraints (two of them, one for San Diego Gas and Electric system and one for the larger Southern California Gas Company system area) in the market for only four days, from January 23 through January 26, 2001. In two of these days (January 24 and 25), the gas system was constrained to such an extent that Southern California Gas Company withdrew gas from Aliso Canyon. The ISO's use of the constraint on these days kept the gas burn of the generators subject to the constraint within the specified limit.

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[13] *Aliso Canyon Gas-Electric Coordination* Revised Draft Final Proposal includes the details for the zonal nature and rules for the gas constraint under Phase 1, available at: http://www.caiso.com/Documents/RevisedDraftFinalProposal_AlisoCanyonGas_ElectricCoordination.pdf. Under Phase 2, the ISO revised select details of the initial design, available at http://www.caiso.com/Documents/RevisedDraftFinalProposal_AlisoCanyonGas_ElectricCoordination.pdf.

[14] See section 6.1.3 of the Revised Draft Final Proposal under Phase 1 for pricing impacts, available at http://www.caiso.com/Documents/RevisedDraftFinalProposal_AlisoCanyonGas_ElectricCoordination.pdf.

Proposal

The following table summarizes the current temporary measures intended to increase gas-electric coordination to address reliability risks caused by the inoperability of the Aliso Canyon natural gas storage facility. For each of these measures, it lists whether the ISO proposes to temporarily extend the measure beyond November 2017, or whether the ISO proposes to make the measure a permanent tariff provision, along with any proposed modifications to the measures.

Temporary Measures	Proposal	Modifications
Maximum Gas Burn Constraint: Ability to enforce gas constraints for either capacity or imbalance limitations and proposes to make refinements to the original constraints design	File permanent revision	Extend authority to entire footprint when conditions warrant in day-ahead and real-time (note: real-time market footprint includes multiple BAAs)
Competitive Path Assessment: Allow the ISO to manually override the dynamic and default competitive path assessment to determine transmission paths should be deemed uncompetitive if the gas constraint is enforced based on a forward competitive path assessment and automate dynamic competitive path assessment to include gas constraint	File permanent revision	Extend authority to entire footprint when conditions warrant in day-ahead and real-time
Virtual Bidding: Ability to suspend virtual bidding in the event the ISO identifies market inefficiencies as result of enforcing the maximum gas burn constraint is only applicable at times the maximum gas burn constraint is enforced	File permanent revision	Extend authority to entire footprint when conditions warrant
D+2 Information: Increase access to information prior to day-ahead by reporting scheduling coordinators' D+2 residual unit commitment results directly to the scheduling coordinator	File permanent revision	No
Day-Ahead Market Gas Index: Increase ability of suppliers to reflect cost expectations in day-ahead bids by using an approximation of the next day gas index published morning of the day-ahead market run to calculate cost estimates	File for temporary extension	No
Adjustments to DEBs and Commitment Cost Caps: Increase the gas commodity price index used to calculate default energy bids (DEBs) and commitment cost for resources in the Southern California Gas and SDG&E gas regions by introducing a commodity price scalar, for purposes of	File for temporary extension	No

distinguishing resources affected by the gas limitations from the rest of the ISO market areas. The percent scalar is applied to the next day gas index published the morning of the day-ahead market run to calculate cost estimates.		

Make permanent gas constraint authority

ISO proposes to make the maximum gas burn constraint a permanent operational tool for use throughout the entire ISO and EIM footprint, as part of their balancing authority role when conditions warrant. The ISO arrived to this proposal primarily based on the following drivers:

- Aliso Canyon is likely to be out for the foreseeable future and the gas constraint has proven useful to mitigate reliability concerns in Southern California in a more transparent manner than use of exceptional dispatches.
- Similar constraints are likely developing in other areas of ISO balancing authority area outside of the Southern California area due to Senate Bill 887 increasing requirements on storage facilities and new CARB rules on storage facility methane leaks.
- Similar constraints exist in portions of the EIM footprint due to gas availability limitations where gas burn levels are not able to exceed limited pipeline capacity, exacerbated by limited levels of storage facilities to mitigate this risk, and the risk of gas system limitations indicated by curtailment watch or operational flow orders.

First, Aliso Canyon is likely to be out for the foreseeable future and the gas constraint has proven useful to mitigate reliability concerns in Southern California in a more transparent manner than use of exceptional dispatches. The gas constraint is a useful tool that can be used in the event of gas system problems to better coordinate with gas system operations and help keep the gas system within operational limits and avoid impacts to electric system reliability. It is preferable to manual dispatches taken by operators because the impact of the gas system constraints are reflected in the ISO market solution (both in locational marginal prices and dispatches) through the use of the gas constraint in the ISO market. Therefore, the constraint reduces the need for manual interventions and uplift on the ISO system.

Second, similar constraints are likely developing in other areas of the ISO balancing authority area outside of the Southern California area such that it finds it prudent to be prepared to manage limitations if needed through gas constraint. ISO believes gas system limitations may develop in other areas within its balancing authority area in the future as a result of higher levels of awareness of adverse impacts if gas storage facilities are unsafely operated. The ISO is concerned potential limitations may develop elsewhere due to potential impacts on gas systems to comply with both the approved Senate Bill initially launched in response to the Aliso Canyon incident that increased requirements on storage facilities (September 2016) and new California Air Resource Board rules aimed at combatting emissions from methane leaks (March 2017)[15].

[15] California Air Resources Board News Release, https://www.arb.ca.gov/newsrel/newsrelease.php?id=907.

The California Legislature declared in its California Senate Bill 887 (SB 887) that, "The standards for natural gas storage wells need to be improved in order to reflect 21st century technology, disclose and mitigate any risks associated with those wells, recognize that these facilities may be in locations near population centers, and ensure a disaster like the Aliso Canyon leak does not happen again.[16]" As a result of this approved bill, Legislature directed the Division of Oil, Gas, and Geothermal Resources to impose additional regulations on gas storage operations among other amendments[17]. Both SB 887 and CARB rules on methane leaks will likely result in potential significant changes to gas storage operations throughout the state – specifically increase risk of system storage capability and availability limitations in both Southern California Gas & Electric and Pacific Gas & Electric systems.

Finally, ISO understands from EIM stakeholders that similar constraints exist in portions of the EIM footprint and as such proposes to seek authority to enforce gas constraints in EIM balancing areas based on the EIM Entity's determination that a gas constraint should be enforced. EIM Entity's already have similar authority to use manual dispatch at their discretion and the gas constraint would provide a more efficient means to managing gas usage. The ISO agrees with Puget Sound Energy (PSE)'s comments on the Aliso Canyon Gas-Electric Coordination Phase 3 straw proposal comments stating, "This tool provides greater flexibility than manually applying outages on select units.[18]"

Based on its understanding of the concerns in EIM Entity balancing authority areas, the ISO believes the existing design for a maximum gas burn constraint with options to apply the either a gas system capacity limitation or a gas system imbalance limitation will effectively respond to the EIM Entities' gas limitations. EIM Entity's use of the gas constraint will follow the existing maximum gas burn constraint policy in which the use of the gas constraint would be limited to managing anticipated physical gas limitations. All generators within the gas constraint would have to be EIM participating resources. The ISO understands EIM Entity gas limitation include:

- Gas capacity reduction limitation: A number of EIM resources have limited pipeline capacity and their gas burn cannot exceed that limited pipeline capacity. In addition, ISO understands that select gas pipeline companies have not offered to sell interruptible transmission over the past several years as well as gas storage is fairly limited for portions of the EIM.[19] Because of this limited storage capacity, on high demand days the ability to draft from the pipeline can become limited and therefore, in combination with limited pipeline capacity and little to no interruptible pipeline capacity available, gas burn levels can be constrained to within gas availability in real-time.

- Gas system imbalance limitation: A number of EIM resources are within gas service areas that are faced with similar operational issues as those originally described in Southern California. Under constrained gas system conditions where pipeline pressure

[16] Section 1(i), https://leginfo.legislature.ca.gov/faces/billCompareClient.xhtml?bill_id=201520160SB887.

[18] Puget Sound Energy (PSE) straw proposal comments, Page 1, http://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=0203E012-3701-45BF-952D-757E2AD4011E.
[19] http://www.westernenergyboard.org/ngei/documents/reference/other/06-12APPIgs.pdf

is imbalanced and could potentially lead to reliability issues, the gas pipeline company will issue instructions to limit the gas burn to within a tolerance band of the scheduled levels so that gas system reliability is not adversely impact.

Given the risk of similar gas limitations arising across the ISO footprint which affects both ISO and EIM balancing authority areas, the ISO believes it prudent to seek authority to enforce maximum gas burn constraints if such limitations arise so that it can manage joint dispatch effectively in real-time. ISO proposes to extend the use of the constraint consistent with the existing design and functionality as described in the Revised Draft Final Proposal from Phase 1 including revisions made under the second phase described in the Draft Final Proposal from Phase 2.[20] Appendix A: Technical appendix on gas constraint in this document includes details on the maximum gas burn constraint design as it would be applied regardless of whether enforced within the ISO or an EIM BAA. ISO notes that each defined generation group nomogram i.e. maximum gas burn constraint is a different constraint but all created similarly using the same principles.

ISO understood from NV Energy and Portland General Electric's comments that the EIM Entity's are seeking more information on the process for using the maximum gas burn constraint, including requirements, notification requirements, or timing of actions needed and how the differences in managing gas-electric coordination outside of the ISO balancing authority area would be captured in those processes[21]. The ISO agrees that establishing the process is a critical piece of the implementation effort needed to support a gas constraint. As described in the background section, the ISO has these procedures – established with the gas company – for the Southern California Gas & Electric area detailing the scenarios under which the constraint could be enforced and actions by ISO, Scheduling Coordinator, or Gas Company; relative timing of the coordination efforts; and notifications associated with triggering the tool.

If authority is approved to use gas constraint in other areas, the ISO will establish guidelines for use of maximum gas burn constraint elsewhere in its operating procedures for addressing adverse operating conditions for gas-electric coordination. Operation procedures are the appropriate location for greater levels of detail beyond the design since the procedures need to be established in coordination with the gas system operator of the affected gas service area if within the CISO balancing authority area or with the energy imbalance market affected service area if within an EIM balancing authority area. The ISO believes the differentiations needed between rules or procedures for ISO balancing authority area versus EIM balancing authority areas s are should be established in coordination with the applicable EIM Entity as the balancing authority area instead of the gas pipeline company would be responsible for (1) establishing operating procedure between the EIM entity and ISO Operations and (2) communicating the EIM entity balancing authority area's need to enforce the constraint to ISO

[20] Available at: http://www.caiso.com/Documents/RevisedDraftFinalProposal_AlisoCanyonGas_ElectricCoordination.pdf, http://www.caiso.com/Documents/DraftFinalProposal-AlisoCanyonGasElectricCoordinationPhase2.pdf.

[21] NV Energy comments, http://www.caiso.com/Documents/NVEnergyComments_AlisoCanyonGas_ElectricCoordinationPhase3StrawProposal.pdf; Portland General Electric comments, http://www.caiso.com/Documents/PGEComments_AlisoCanyonGas_ElectricCoordinationPhase3StrawProposal.pdf.

Operations, and (3) would designate all generators' within the maximum gas burn constraint as EIM participating resources at the time the constraint is enforced.

NV Energy sought information on how enforcing a maximum gas burn constraint. The ISO confirmed that the sufficiency test does not consider the deliverability of that capacity as a requirement for the test today. Enforcing the maximum gas burn constraint will not impact the test to maintain consistency with the current policy around the test where transmission constraints are also not considered.

ISO notes that the maximum gas burn constraint has always been planned to be implemented in two phases where phase 1 hardcoded the $\propto_i$ so that it is the average heat rate for a resource that is programmed into the nomogram as hardcoded shift factors instead of the unit factor (shift factor of 1) for every resource and phase 2 will incorporate the heat rate specific to the bid segment curve output by the market process as described in the equation so that the shift factors will return to unity as designed. As a part of making this functionality a permanent feature, the ISO will fully implement the maximum gas burn constraint and complete phase 2.

Automate dynamic competitive path assessment to include gas constraint

The ISO proposes to automate the inclusion of the natural gas constraint into the dynamic competitive path assessment as the full technology solution to the mitigation concerns. To resolve these concerns today when the ISO enforces the maximum gas burn constraint, the ISO has the authority to override both its dynamic and default competitive path assessments when the gas constraint is enforced based on actual system conditions.

As part of each market power mitigation run, a dynamic competitive path assessment (DCPA) is performed to determine whether a transmission constraint is uncompetitive. A transmission constraint will be competitive by default unless the transmission constraint is determined to be uncompetitive by the DCPA. This will occur when the maximum available supply of counter-flow to the transmission constraint from all portfolios of suppliers (not identified as potentially pivotal) is less than the demand for counter-flow. If, for some reason, the DCPA is unable to function or for the purpose of mitigating incremental exceptional dispatches that could have relieved the transmission constraint, the market power mitigation will rely on a default competitive path list which is compiled based on historical analysis of congestion and previous DCPA results on each transmission constraint.

At times when gas-usage nomograms may be enforced, the simultaneous impact of enforcing both the maximum gas burn constraint and the transmission constraint is not included in the DCPA methodology.

To address this gap, the ISO performs a manual procedure the forward competitive path assessment to determine whether there is a need to manually declare transmission constraints uncompetitive based on its determination that actual electric supply conditions may be uncompetitive due to anticipated electric supply conditions in the affected gas regions. As a part of the forward competitive path assessment, the ISO first will identify the set of transmission constraints that can be relieved by counter-flow from potentially gas-limited resources. Then, the

ISO will estimate changes to the residual supply index (RSI) for each of those constraints resulting from the imposition of different values of the gas usage nomograms for each day. Estimation of the RSI will involve identical calculations to the ones used in the market, but will include an estimate of the capacity that is operationally available after the imposition of the gas-usage nomograms. The ISO will be able to declare a set of constraints uncompetitive where the RSI is predicted to be uncompetitive with the inclusion of the maximum gas burn constraint nomogram. Finally, Operations will be provided with a table that lists the relevant potentially uncompetitive transmission constraints based on maximum gas burn constraint levels enforced. For each constraint and maximum gas burn constraint combination, a limit or limits will be listed. If the maximum gas burn constraint(s) is binding with a limit at or below the one listed, it will be appropriate to declare the listed constraints uncompetitive if identified as uncompetitive based on the forward competitive path assessment.

Given its belief that the manual override mitigates risks to market power concerns when the maximum gas burn constraint is enforced, the proposal is to maintain authority to override the dynamic or default competitive path assessment until the full solution is effective. In this way, the existing process can be used to bridge to a full solution allowing authority to enforce gas constraint across footprint if conditions warrant while ensuring the potential impact of the constraint is incorporated in market power mitigation processes. The ISO will need to evaluate the workload associated with using the manual override while enforcing gas constraints in additional areas and may need to phase in implementing these constraints.

The ISO commits to providing additional transparency around the competitive path assessment. If a manual override were to be issued, the ISO would notify the market at the time it enforced the constraint.

Make permanent virtual bidding suspension authority

Along with making the gas constraint a permanent operational tool, the ISO proposes to also make permanent authority to suspend virtual bidding in the event virtual bids are introducing adverse market outcomes in conjunction with the use of the gas constraint (this would not be applicable to EIM areas as there is no virtual bidding at those locations). As explained in the previous Aliso Canyon Gas-Electric Coordination proposals, this is an important measure to mitigate adverse market outcomes in conjunction with the use of the gas constraint.

The ISO commits to providing additional transparency around the authority to suspend virtual bidding. The ISO maintains its previous commitment to issue a technical bulletin with justifications for a general suspension or limitation of Virtual Bids if suspended using this authority.

Make permanent publishing the D+2 Information

This measure increases access to information prior to day-ahead by reporting scheduling coordinators' D+2 residual unit commitment results directly to the scheduling coordinator. The ISO proposes to make these permanent tariff provisions because it believes this will continue to be useful information to suppliers to incorporate into their gas procurement conducted in the morning before the ISO publishes day-ahead market results at 1 pm. The majority of gas trading occurs before the ISO publishes day-ahead market results and suppliers have stated that although the D+2 results are not complete predictors of day-ahead market results, they are a useful data point in making their gas procurement decisions.

ISO will continue to pursue enhancements to increase access to information to scheduling coordinators and the gas companies to support gas-electric coordination below. Since the ISO does not need to make additional tariff revisions to increase transparency into gas-electric needs, ISO commits to continue to improve this transparency where practical through either providing:

- More than 24 hours of gas burn data so the gas company can see operating expectations across its operating day from 7AM-7AM Pacific,
- Real-time gas burn information, or
- Unit-level RUC gas burn amounts to both gas company and scheduling coordinators[22] for each gas burn amount reported to the gas company.

Extend temporarily market measures

As described in the table above, the ISO proposes to further extend some of the current temporary market measures designed to increase gas-electric coordination in light of the limited operability of the Aliso Canyon natural gas storage facility. As described below, these measures will likely no longer be needed once the ISO implements market design changes being developed under the ISO's current *Commitment Cost and Default Energy Bid Enhancements* policy initiative. The CCDEBE enhancements are currently planned to be effective as of fall 2018. Consequently, the ISO proposes to extend these temporary measures until it implements these long-term changes.

The following discuss the temporary measures the ISO proposes to further temporarily extend:

Day-Ahead Market Gas Index: This measure increases the ability of suppliers to reflect cost expectations in day-ahead bids by using an approximation of the next day gas index published the morning of the day-ahead market run to calculate cost estimates used for default energy bids, generated bids, and commitment cost bid caps (cost estimates). The ISO proposes to extend it to continue to estimate suppliers' costs at cost estimates that more accurately reflect current gas market prices.

The ISO is proposing to temporarily extend this measure, instead of making it permanent, because it is considering bidding rule and cost estimates changes in the ongoing Commitment Cost and Default Energy Bid policy initiative that will also increase the accuracy of cost estimates used by the day-ahead market.

Adjustments to DEBs and Commitment Cost Caps: These measures increase the gas commodity price index used to calculate cost estimates for resources in the Southern California

[22] Scheduling Coordinator would only receive its assets gas burn information.

Gas and SDG&E gas regions by introducing a commodity price scalar, for purposes of distinguishing resources affected by the gas limitations from the rest of the ISO market areas. The percent scalar is applied to the next day gas index published the morning of the day-ahead market run to calculate cost estimates. The ISO proposes to extend these three temporary measures that made adjustments to its cost estimates to improve commodity price information or to include additional short-run marginal costs associated with generator's managing their balancing requirements.

Based on the recent summer 2017 assessment, and as was the case over both summer 2016 and winter 2016/2017, the ISO anticipates that (1) Aliso Canyon will have only limited operability, (2) intra-day (i.e., real-time) gas availability will likely decrease, and (3) there will be tightened gas balancing requirements. This means a lack of nearby gas storage to respond to electric ramping needs and, when there is a deterioration of gas pipeline pressures, limited ability for SoCalGas and SDG&E to support large increases of gas receipts onto their systems relative to their scheduled capacity or deliver the increased amounts of gas in real-time to generators. ISO expects that the current commitment costs, generated bids, and default energy bids likely will not fully accommodate these conditions. Because the ISO's current calculation of the gas commodity price is based on trading for next-day delivery, it does not include information from the intra-day gas commodity markets regarding gas prices or risk of noncompliance with gas balancing rules. Therefore, absent the tariff provisions that the ISO proposes to maintain in this filing, the resulting commitment costs, generated bids, and default energy bids may not allow resources to manage gas-balancing requirements within tightened tolerance bands, and the calculated gas price may not fully capture real-time gas commodity prices on all days. When generators on the affected gas system are under tightened gas balancing requirements, they will presumably reflect these tightened balancing requirements in their bids, which will likely achieve the desired result of the real-time market dispatching these resources only for local electrical needs.

Under the existing policy effort CCDEBE, the ISO is evaluating with stakeholders bidding rule changes should be made to more accurately reflect gas costs in cost estimates when the gas system is adversely affected by constrained conditions so as to continue to differentiate between generators that are at risk of violating balancing rules and those that have gas available to respond to dispatch. The ISO is developing a straw proposal to propose long-term solution that will continue to allow market dispatches and prices to reflect resources' expected costs even under constrained gas system conditions.

Plan for Stakeholder Engagement and Next Steps

The current schedule for this initiative is shown below. Stakeholder comments will be due June 14, 2017. In comments, the ISO asks stakeholders to provide input on the ISO's straw proposal. The ISO will present its proposal to its Board of Governors and the EIM Governing Body during their July 2017 meetings.

> In this draft final proposal the CAISO has revised its plan for obtaining approval from the EIM Governing Body and CAISO Board. In the straw proposal, the CAISO had stated

the entire initiative would involve the EIM Governing Body's advisory role. The CAISO now plans to divide the initiative into two separate parts for decisional purposes. It would seek approval under the EIM Governing Body's primary authority for the element of this initiative that proposes to allow an EIM Entity to implement a gas constraint in its balancing area. The remainder of the initiative will involve the EIM Governing Body's advisory role to the Board of Governors.

The CAISO made this change after recognizing that the use of gas constraints in EIM areas is separable from the rest in the sense that, even if this particular component were not approved at this time, Management would plan to file the remainder of the proposal if it were approved because it relates to the distinct issue of Aliso Canyon. This approach is consistent with the guidance in section II.B. of the *Guidance for Handling Policy Initiatives within the Decisional Authority or Advisory Role of the EIM Governing Body.*[23] This section addresses when an initiative contains a severable component that CAISO management would plan to file for approval whether or not another components or components are approved. In such a case, it states that "…any severable EIM-specific element should be separated after the conclusion of stakeholder review and directed to the EIM Governing Body for decision. The severable EIMs specific element (alone) should be directed to the EIM Governing Body as part of primary authority. The remainder of the initiative should be classified according to the applicable rules."

Milestone	Date
Issue and Straw Proposal Posted	06/02/2017
Stakeholder Call	06/07/2017
Stakeholder Written Comments Due	06/14/2017
Draft Final Proposal Posted	06/22/2017
Stakeholder Call	06/23/2017
Stakeholder Written Comments Due	06/30/2017
EIM Governing Body Meeting	6/13/2017
July Board Meeting	07/26/2016

[23] http://www.caiso.com/Documents/GuidanceforHandlingPolicyInitiatives-EIMGoverningBody.pdf

Appendix A: Technical appendix on gas constraint

Enforce generation group nomogram to constrain burn levels

Problem statement

The ISO understands the two primary factors that can adversely impact the gas system reliability, and consequently electric system reliability, are:

1. Capacity reduction limitations from storage outages, pipeline outages, or curtailments: Whether planned or unplanned, outages or curtailments will restrict the availability of gas to affected generators. A plant level limitation reflecting an agreed upon maximum allowable gas burn could be reflected in ISO markets so the ISO can more efficiently dispatch the generators under the limitation.

2. System imbalance limitation where large imbalances between gas nominations and actual gas burn could compromise gas reliability: Electric operations can affect gas reliability if electric market outcomes result in instructing affected generators to increase or decrease their gas imbalances to respond to ISO instructions. For example, a significant change in the dispatch of generators in the SoCalGas and SDG&E gas system between the real-time dispatch and day-ahead market schedules could exacerbate the decline (for low operating pressure condition) or the increase (for high operating pressure condition) of operating pressure if generators are not able to adjust either their nominations or their gas burn to a level more supportive of gas system conditions. The technical assessment concluded that daily gas imbalances greater than 150 MMcf[24] in either direction significantly increase risk of gas curtailments that could result in electric service interruptions.

Discussion on (1) capacity reduction limitations

Current ISO policy in the event of a reduction in gas system capacity or deliverability capability is to allow generators to manage their output so that it reflects the reduction from gas outages and/or curtailments.

For outages, the ISO's policy is that once these outages are made public by the gas company, the generators are responsible for submitting its plant level limitation through the outage management system using the appropriate nature of work. The ISO's current policy places the responsibility on the generator to ensure it submits an outage card to the ISO's outage management system reflecting a limitation it might expect unless timing precludes the outage card from being reflected in the market. While an outage may be public, it may be unclear to generators exactly what their plant level limitation will be until the curtailment or their inability to procure gas occurs. While it would improve electric market outcomes if generators submitted outage cards reflecting their share of the gas limitation as result of outage, generators might not be able to translate the outage information to a plant level limitation. Further once a notification

[24] The ISO will continue to explore with SoCalGas its understanding of the exact constraint and in the meantime uses 150 MMcf for the purpose of describing the proposed priced constraint.

is issued for curtailments, the ISO is evaluating whether operations could be improved through using the gas constraint to reflect curtailments instead of issuing exceptional dispatches when timing does not allow outage cards to be reflected in the current market run.

For curtailments, operating procedure 4120 and 4120c detail the communication and actions taken to ensure curtailments are reflected to support gas and electric reliability. ISO policy for addressing curtailments is that if time allows, the gas company is responsible for communicating plant level limitations and the generator is responsible for submitting these plant level limitations to the ISO outage management system with a nature of work 'ambient not due to temperature'. If an outage card is submitted later than 37.5 minutes prior to the real-time market interval, the real-time market run for that interval will not reflect the limitation. In this instance, the ISO will issue exceptional dispatches so the plant level limitations are consistent with what gas curtailment notifications would have been received by the generator are reflected in the market.

If determined the ISO has more latitude to allocate curtailment amount across its electric generator's based on more refined criteria rather than a pro rata curtailment, the ISO could enforce a gas constraint to reflect the capacity reduction limitation in its markets where the constraint would limit the maximum allowable gas burn for the affected area in each market run based on an hourly limit provided to it by either the affected gas company or EIM entity BAA. For example, SoCalGas might notify the ISO of curtailment notification such that they would specify the gas operating zone(s) affected, the hours the curtailment will be in place (e.g. HE15 – HE18), and the maximum allowable burn for the hours which could vary across hours (e.g. 1 BCF for HE15, 1 BCF for HE16, 1 .5 BCF for HE17, and 1.5 BCF for HE18).

<u>Discussion on (2) system imbalance limitations</u>

According to the technical assessment report, the constraint on the gas system is not a flexible constraint once certain conditions are present and in those instances the range should not exceed the identified range that can be supported by the gas company. The conservative range noted in the report was 150 MMcf/d which is the amount the gas system can support on days with high demand usage relative to its overall system capacity. Gas operations with its day-ahead demand forecast can inform the extent to which this range can widen to support more imbalances.

If the gas reliability concern likely to impact electric service is anticipated to be a daily concern the ISO would default to enforcing a limit on gas burn in real-time until gas market structural changes are made to increase the ability of the gas system to support larger demands or imbalances over a day. On the other hand, if the risk to reliability imposed by large demands or imbalances is only present on days when certain fundamental factors are present the enforcement of this constraint would be triggered based on the fundamental factor(s). The ISO commits to coordinate with the affected gas company or EIM entity BAA and would apply maximum gas burn constraint in the market based on anticipated or observed needs.

To increase the affected generators ability to respond to electric service needs in real-time based on electric system needs, the ISO will allocate any daily range across hours based on the expected load shape.

Constraint details

The ISO proposes to implement a constraint in its day-ahead or real-time market, or both, that would limit the affected area gas burn to a gas burn limitation reflecting gas system limitations for either capacity reduction limitations or system imbalance limitations. If ISO operations determined additional generation from the affected generators is needed beyond the limits of the constraint enforced, the additional generation could only be dispatched through exceptional dispatches or EIM manual dispatches based on coordination with gas system operator or EIM entity BAA.

Defining affected generators under gas constraint(s)

This gas constraint will be implemented using generation nomograms where the generation nomogram is defined by a set of generators each with a unity shift factor (dfax=1) to the transmission paths within the area so the nomogram limits the area's generators to a maximum gas burn level. In the following section on Modeling the generation group nomogram, the nomogram functionality is described in detail where the nomogram variable type used for this constraint is V_3.

The affected area, or the set of generators included under the gas constraint(s), will be the gas fired generation within the gas operating zone(s) identified by gas company or EIM entity BAA as under the maximum gas burn limitation. If the entire system is affected, the constraint would encompass the entire gas company's service area or the entire EIM entity BAA. Depending on which gas operating zones are under restricted system limitations, the affected area could be one gas operating zones, a selection of gas operating zones, or the entire gas system. If gas system limitation is anticipated or identified that would impact more than one gas operating zone but not inclusive of the system-wide generation nomogram, the ISO will allocate the multi-zone limitation to the individual gas operating zones.

The ISO and gas company or EIM entity BAA will collaborate to identify generator groups likely to need to be constrained to manage a capacity or imbalance limitation. The generation group nomograms will be defined to include those resources.

Since the constraint will need to be able to move resources dispatch levels relative to the base schedule, the ISO will require the EIM entity to designate all generators defined within the nomogram as participating resources for the market runs where the constraint is enforced.

General constraint formulation

Equation 1: Gas Constraint(s)

$$\sum_{i \in S} \alpha_i \left(G_{i,t}\right) \leq RHS_t$$

S	Set of generators in affected area (1 or more gas operating zones)

G	Power output (MW)
$\propto_i$	Energy (MW) to million cubic feet (MMcf) gas conversion factor (Masterfile heat rate value at given MW output * unit conversion factor)
RHS_t	Right hand side limit enforcing upper bound constraint (different limit formulation for capacity versus imbalance limitations)

The criteria for enforcing the limits would differ depending on whether (1) it's a total gas burn limitation (absolute value MMcfd) versus incremental gas burn limitation (relative MMcfd amount relative to baseline), (2) daily or hourly limitation, and (3) limit provided by the gas company or default value.

<u>Total gas burn limitation due to reduction in capacity or deliverability</u>

Equation 2 defines the constraint limits for a maximum allowable total gas burn due to reductions in system capacity or deliverability. The upper bound limit defines the maximum allowable total gas burn communicated to the ISO from the gas company or the EIM entity BAA. When this maximum limit is enforced and ISO operations determines additional generation from the affected generators is needed above this limit for electric reliability, the additional generation would only be dispatched through exceptional dispatches or EIM manual dispatches once coordinated with the gas system operator or EIM entity BAA.

The upper bound constraint used to reflect gas system limitations due to outages or curtailments could either reflect a gas system limitation daily or hourly depending on the type of capacity reduction. A system capacity reduction from outages could tend to last for several days and appear as a daily limitation where a system capacity reduction from curtailments or emergency flow orders issued to respond to deteriorating system conditions generally occur for specific hours at hourly amounts.

The ISO would distribute the daily limitation across the hours based on a ratio of hourly load forecast to daily load forecast to support greater electric flexibility, if provided an hourly burn limit the value would be input individually for each hour. To further enhance the flexibility of this constraint, the ISO proposes to have the flexibility to recapture portions of the allocated range unused for earlier intervals if necessary. For example, if balancing range allocated to the first 4 hours of the day was unused, the gas burn associated with that allocation would be recaptured and used to increase the allowable range for later periods consistent with expected load shape. ISO Operators or EIM entity BAAs will be provided flexibility to input allowance distribution coefficients that they believe would better support electric operations than the default method. For example if the gas constraint was enforced for all 24 hours but Operators felt that an equal distribution across the hours would better support gas-electric operations, the Operators or EIM entity BAA could override the default through inputting ~4% as the distribution factor for each hour.

Equation 2: Gas Capacity Reduction Limitation

$$Where\ limit\ is\ set\ as\ follows:$$

$$RHS_t = \gamma_t\, R_h$$

$$\sum_{1}^{N} \gamma_t = 1$$

$\boldsymbol{R_h}$	Amount of generation expressed in MMcf/d that the ISO determines or that the EIM entity BAA has communicated to the ISO is necessary to manage gas limitations and operate the electric system reliably
γ_t	Allowance distribution coefficients associated with upper bound limit that distributes a MMcf/d amount over the intervals of a trading day based on ratio of hourly load forecast to daily load forecast, if provided an hourly burn limit and not a daily limitation this value will be 1

When notified of a gas limitation requiring the enforcement of the gas constraint, the ISO requests to be notified of the following details: (1) affected area, (2) affected hours, and (3) maximum allowable gas burn for each hour. For example, if the gas company notifies the ISO it will have an outage on its pipelines reducing the availability of fuel in a defined zone to an expected maximum amount prior to the day-ahead market close, the constraint would be enforced in both day-ahead and real-time. If an unplanned outage occurs after day-ahead or curtailment is issued during real-time, the constraint could be enforced in real-time market run.

Incremental gas burn limitation

Equation 3 defines the constraint limits for a maximum allowable incremental gas burn due to concerns about deteriorating pipeline pressure on the gas system. The upper bound limit defines the maximum allowable incremental gas burn the gas system can support and maintain reliable operations, generally communicated to the ISO from the gas company or EIM entity BAA. When this maximum incremental limit is enforced and ISO operations determines or EIM entity BAA communicates that additional generation from the affected generators is needed above this limit for electric reliability, the additional generation would only be dispatched through exceptional dispatches or EIM manual dispatches once coordinated with the gas system operator or EIM entity BAA.

A significant change in the ISO's dispatch from day-ahead to real-time if generators are not successful in adjusting nominations to compensate for change can lead to compromising the gas operating pressures. This constraint, since it is relative to the day-ahead schedule or EIM base schedules, would be enforced in real-time as a daily limitation representing the incremental amount (MMcf/day) the real-time dispatch can deviate from the day-ahead schedule or EIM base schedules.

The ISO would distribute the daily limitation across the hours based on a ratio of hourly load forecast to daily load forecast to support greater electric flexibility. To further enhance the flexibility of this constraint, the ISO proposes to have the flexibility to recapture portions of the allocated range unused for earlier intervals if necessary. For example, if balancing range allocated to the first 4 hours of the day was unused, the gas burn associated with that allocation would be recaptured and used to increase the allowable range for later periods consistent with expected load shape. ISO Operators or EIM entity BAAs will be provided flexibility to input allowance distribution coefficients that they believe would better support electric operations than the default method. For example if the gas constraint was enforced for all 24 hours but Operators felt that an equal distribution across the hours would better support gas-electric operations, the Operators or EIM entity BAA could override the default through inputting ~4% as the distribution factor for each hour.

Equation 3: Gas System Imbalance Limitation

$$Where\ limits\ are\ set\ as\ follows:$$

$$RHS_t = \gamma_t \left[R_h + \sum_{i \in S} \alpha_i \left(\bar{G}_{i,t} \right) \right]$$

$$\sum_{1}^{N} \gamma_t = 1$$

S	Set of generators in affected area
$\bar{G}$	Day-ahead market schedule or EIM base schedules
$\propto_i$	Energy (MW) to million cubic feet (MMcf/day) gas conversion factor (Masterfile heat rate value at given MW output * unit conversion factor)
R_h	Daily upper bound deviation allowance relative to day-ahead market schedule, this value can only be greater than or equal to 0[25].
γ_t	Allowance distribution coefficients associated with upper bound limit that distributes a MMcf/day amount over the intervals of a trading day based on ratio of hourly load forecast to daily load forecast

The ISO would enforce this constraint for:

- Real-time hours once the gas company or EIM entity BAA has issued or anticipates issuing a low operational flow order or curtailment warning or watch notifications. The

[25] Adding clarity that the incremental constraint is incremental to day-ahead residual unit commitment schedules so must be greater than or equal to zero.

ISO would enforce the side of the constraint of the OFO. The MMCF/day amount of the R_h representing incremental burn the gas system can support would be dynamic if provided by the gas company or EIM entity BAA. If not provided but ISO anticipates reliability concerns within its BAA, the ISO would be able to enforce maximum gas burn constraints within the ISO BAA at a default amount of 105% of the aggregate burn amount from the day-ahead RUC schedules.

- For days where the ISO anticipates its load forecast may have a large error resulting in significant re-dispatches in the real-time market. The magnitude of such re-dispatch especially if day-ahead gas demand forecast is high implying a smaller imbalance tolerance, the ISO needs the authority to limit the re-dispatch in real-time as a preventive measure. By limiting the re-dispatch the ISO would not be issuing real-time dispatch instructions that could compromise the gas system reliability. Used in such a manner, the electric operator would be enforcing the constraint to avoid gas system conditions that could result in curtailments. The MMCF/day amount of the R_h representing incremental burn the gas system can support would be dynamic if provided by the gas company or EIM entity BAA. If not provided but ISO anticipates reliability concerns within its BAA, the ISO would be able to enforce maximum gas burn constraints within the ISO BAA at a default amount of 105% of the aggregate burn amount from the day-ahead RUC schedules.

Pricing impacts

The nomogram segment would have a shadow price associated with it reflective of a penalty price associated with relaxing the constraint. If the market cannot come to a feasible solution without violating the constraint, then the LMP for generators subject to the constraint will reflect the constraint penalty price. The ISO will establish this penalty price to function appropriately relative to the other penalty prices used by the market.

The constraint parameter establishing the penalty price for the gas constraint is a "penalty factor," which is associated with constraints on the optimization and which govern the conditions under which constraints may be relaxed and the setting of market prices when any constraints are relaxed. Importantly, the magnitude of the penalty factor values for each constraint for each market reflects the hierarchical priority order in which the associated constraint may be relaxed in that market by the market software relative to other constraints. A negative penalty price is used to reflect the need to reduce supply, a positive price is used to reflect the need for demand reduction, and for some constraints either a negative and positive price could be used.

The ISO believes the gas constraint should ideally have a lower priority than the electric transmission constraints. Table 1 below shows the ideal relative priority of the gas constraint to the other constraints market parameters described in the Market Operations BPM[26]. Currently, the ISO will relax the gas constraint consistent with electric generation group nomograms seen

[26] Market Operations BPM on Pages 179 – 186, available at: https://bpmcm.caiso.com/BPM%20Document%20Library/Market%20Operations/Market%20Operations%20BPM%20Version%20%2045_clean.doc.

in lines describing “Transmission constraints: Intertie scheduling, branch, corridor, **nomogram** (base case and contingency analysis).”

Table 1: Relative priority of relaxation of gas constraint

Market	Penalty Price Description	Scheduling Run Value	Pricing Run Value	Comment
IFM	Transmission constraints: Intertie scheduling, branch, corridor, nomogram (base case and contingency analysis)	5000	1000	Intertie scheduling constraints limit the total amount of energy and ancillary service capacity that can be scheduled at each scheduling point. In the scheduling run, the market optimization enforces transmission constraints up to a point where the cost of enforcement (the “shadow price” of the constraint) reaches the parameter value, at which point the constraint is relaxed. Ideally electric transmission constraints would have higher priority than the gas burn transmission constraint.
	Transmission constraints: gas burn nomogram			
	Ancillary Service Region Regulation-up and Regulation-down Minimum Requirements	2500	250	In the event of bid insufficiency, AS minimum requirements will be met in preference to serving generic Self-Scheduled demand, but not at the cost of overloading transmission into AS regions.
RUC	Transmission constraints: branch, corridor, nomogram (base case and contingency analysis)	1250	250	These constraints affect the final dispatch in the Real-Time Market, when conditions may differ from Day-Ahead.
	Transmission constraints: gas burn nomogram			
	Limit on quick-start capacity scheduled in RUC	250	0	Limits the amount of quick-start capacity (resources that can be started up and on-line within 5 hours) that can be scheduled in RUC. For MRTU launch the limit will be set to 75%.

RTM	Transmission constraints: branch, corridor, nomogram (base case and contingency analysis)	1500	1000	Scheduling run penalty price will enforce internal transmission constraints up to a re-dispatch cost of $ of congestion relief in $1500 per MWh. Energy bid cap as pricing run parameter consistent with the value for energy balance relaxation under a global energy supply shortage.
	Transmission constraints: gas burn nomogram			
	Ancillary Service Region Maximum Limit on Upward Services	1500	250	Scheduling run penalty price is lower than those for minimum requirements to avoid otherwise system-wide shortage by allowing sub-regional relaxation of the maximum requirement. AS market bid cap as pricing run to reflect the otherwise system-wide shortage.

Enhancements may be needed and would be taken under the business practice manual revision process to ensure the goal of reflecting a lower priority than the electric transmission constraints is observed in the market.

Due to the ISO's market design and the functionality of a generation group nomogram, the constraint will affect the resource specific price at the connectivity node (CNode) used to dispatch affected generators. The affected generators will settle off of the resource specific price at the CNode where the penalty price reflected in the CNode LMP when relaxed will ensure the generation under the nomogram will not be dispatched higher or lower than the constraints' limits. When relaxed:

- For a maximum gas burn limit, the CNode LMP will be lowered to ensure the necessary supply reduction occurs.
- For a minimum gas burn limit, the CNode LMP will be increased to ensure the necessary supply increase occurs.

All generators under a maximum gas burn constraint will not be able to be settled off of their Point of Delivery (POD) LMP, the POD is the same FNM node as the POR Pnode. All other market participants will be settled off of the pricing node locational marginal prices. What does this mean? This means that the nomogram segment shadow price is not included in the pricing node locational marginal prices used for settling:

- Injections received into the ISO Controlled Grid for Supply **for generators outside of maximum gas burn constraint areas**
- Withdrawals delivered out of the ISO Controlled Grid for Demand,
- Virtual bids or congestion revenue rights for those injection and withdrawal locations, and (CRR).

In short, the nomogram constrains only the specific resources it applies to; it does not apply to any other injection at the same location, thus its shadow price is not reflected in the PNode LMP, but only in the CNode. As discussed in detail in the following section, this is because for nomogram variables with aggregate generating resource output (i.e. V_3) the shift factor is set to 0 and will not be included in the locational marginal price at the PNode. This is similar to the difference between the SP-TIE price for an intertie schedule and the SP LMP for load at that location. The SP-TIE LMP includes contributions from constraints that apply only to the intertie schedule, but not the load.

Modeling the generation group nomogram

Introduction

A nomogram is a set of piece-wise linear inequality constraints relating transmission corridor MW flows and MW generation. (Note that if one wanted to use the MW flow on a single branch as part of a nomogram definition then a single branch transmission corridor would need to be defined.) Resource statuses cannot be part of the nomogram model. The constraints must be piecewise linear defining a convex set. **Nomograms can consist of a family of piecewise linear constraint curves. The constraint curve that is active for a given Trading Hour (or set of Trading Hours) is manually selected by the user prior to the optimization.**

An individual nomogram variable can be one of the following:

a) A transmission corridor MW flow value.

b) A Nomogram Generation Group MW output value. This is the sum of the MW output of the individual market generating resources or aggregate market generating resources that make up the nomogram generation group.

The following are examples of typical nomogram variable combinations:

a) Transmission Corridor MW Flow vs. Transmission Corridor MW Flow.

b) Transmission Corridor MW Flow vs. Area MW Generation.

The nomogram constraint presents a family of piecewise linear curves relating one or more nomogram variables. The Nomogram constraints relating variables $V_n\,;\ \ where,\ n=1,2,\ldots,N$ imposed by $k=1,2,\ldots,K$ linear segments of an active piecewise linear nomogram curve can be expressed as follows:

$$a_1^k \cdot V_1 + a_2^k \cdot V_2 + \ldots + a_n^k \cdot V_n + \ldots + a_N^k \cdot V_N \leq b^k; \quad k=1,2,\ldots,K$$

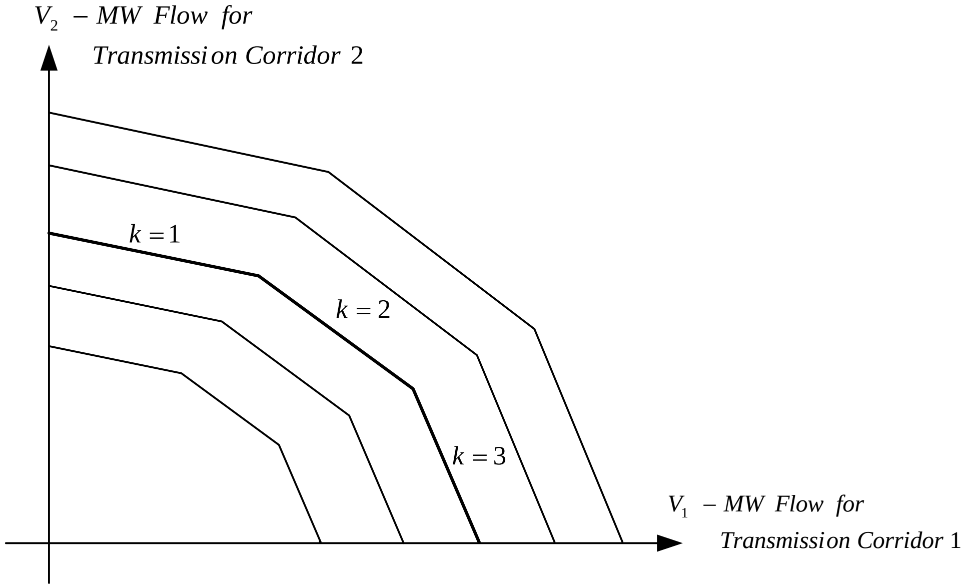


Figure 1. A Typical Nomogram Constraint

For example, the nomogram shown on above diagram relates a transmission corridor (corridor 1) MW Flow variable:

$$V_1 = Flow_{corr1}^{base,t} + \Delta Flow_{corr1}^{t} = Flow_{corr1}^{base,t} + \sum_{node \in corr1} SF_{corr1}^{node} \cdot \left(P_{node}^{t} - P_{node}^{base,t}\right)$$

To another transmission corridor (corridor 2) MW Flow variable:

$$V_2 = Flow_{corr2}^{base,t} + \Delta Flow_{corr2}^{t} = Flow_{corr2}^{base,t} + \sum_{node \in corr2} SF_{corr2}^{node} \cdot \left(P_{node}^{t} - P_{node}^{base,t}\right)$$

For a selected nomogram constraint curve the following three segments are specified:

$$a_1^1 \cdot V_1 + a_2^1 \cdot V_2 \leq b^1$$ for segment k = 1,

$$a_1^2 \cdot V_1 + a_2^2 \cdot V_2 \leq b^2$$ for segment k = 2,

$$a_1^3 \cdot V_1 + a_2^3 \cdot V_2 \leq b^3$$ for segment k = 3.

The active nomogram constraint curve is manually selected by the user prior to the optimization process from a pre-specified set of piecewise linear curves.

Other nomogram variables can be the energy generation of some group of generating units:

$$V_3 = \sum_{unit \in G} En_{unit}^{t}$$

No other types of variables are supported.

Notation

The notation used for these equations is the same as used in the IFM DDS with the following extensions for nomograms:

t	time interval index
$node$	node index
$unit$	generating unit or import system resource index
$load$	dispatchable load or export system resource index
$line$	network branch (line or corridor) constraint index
nm	is a subscript referring to a particular nomogram
nv	is a subscript referring to a particular nomogram variable for a particular nomogram
nc	is a subscript referring to the active curve for a particular nomogram at time *t*. For every nomogram there may be multiple curves defined but only one of them can be active in a given Trading Hour.
ns	is a subscript referring to a particular nomogram segment for a particular active nomogram curve for a particular nomogram
ntc	is a subscript referring to a particular transmission corridor that is associated with a nomogram variable
$a_{nv}^{nm,nc,ns}$	is the coefficient of segment *ns* of the active curve *nc* of nomogram *nm* that corresponds to the nomogram variable *nv*
$b^{nm,nc,ns}$	is the right hand side value of segment *ns* of the active curve *nc* of nomogram *nm*
$SF_{nm,nv}^{node}$	is a shift factor indicating how the nomogram variable *nv* of nomogram *nm* changes due to an incremental injection into the system at the pnode location *node*.
$SF_{nm,nc,ns}^{node}$	is a shift factor indicating how the left hand side value of segment *ns* of the active curve *nc* of nomogram *nm* changes due to an incremental injection into the system at the pnode location *node*.
$NSCP_{nm,nc,ns}^{t}$	is the nomogram segment clearing price (i.e., shadow price) for the nomogram segment *ns* of the active curve *nc* of nomogram *nm* at time *t*
$\overline{P}_{nm,nc,ns}^{viol;t}$	is the violation or infeasibility slack variable for segment *ns* of the active curve *nc* for nomogram *nm* at time *t*
$C(\overline{P}_{nm,nc,ns}^{viol;t})$	is the contribution to the objective function for the infeasibility slack variable for segment *ns* of the active curve *nc* for nomogram *nm* at time *t*
p_{NM}^{viol}	is the infeasibility slack variable penalty price for nomograms
GG	refers to the set of generation resources that make up a specific generation group
NN	refers to the set of nodes.
T	refers to the time horizon
G	refers to the set of generating units or import system resources
L	refers to the set of dispatchable loads or export system resources
LL	refers to the set of network branch (line or corridor) constraints
NM	refers to the set of all nomograms
NMV_{nm}	refers to the set of nomogram variables associated with nomogram *nm*
$NMS_{nm,nc}$	refers to the set of nomogram segments associated with active curve *nc* of nomogram *nm*
P_{node}	is the energy injection at node *node*
En	is the energy schedule of a given resource

$V^{t}_{nm,nv}$	is the value of the nomogram variable corresponding to nomogram *nm* and variable *nv* for time *t*
MCP	is the shadow price of the power balance constraint
pf_{node}	is the loss penalty factor at node *node*
TCP	is the shadow price of a network constraint on a transmission branch or corridor

Generation Group Nomogram Variable Equation

This section provides the formulation details for generation groups that are defined as a nomogram variable. Basically this nomogram variable consists of the sum of the MW outputs of a subset of generation resources within the system. There are some key observations to make regarding this definition. The first relates to which generation resources are part of the subset. The following restrictions should be made on the subset:

- Permitted values within a generation group
  - Individual generation resources
  - Aggregate generation resources. If an aggregate generation resource is defined as part of a generation group then all of the members of the aggregate resource will be part of the generation group.

  System Resources (import/exports) will not participate in nomograms, but transmission corridors defined for inter-ties can be defined as nomogram variables.
- Values not permitted within a generation group
  - Only a subset of the units in an aggregate generation resource. Either the entire aggregate generation resource should be included within a generation group or none if it should be.

The equation for a generation group nomogram variable can be written as follows:

$$V^{t}_{nm,nv} = \sum_{unit \in GG} En^{t}_{unit}; \quad nm \in NM; nv \in NMV_{nm}; t \in T$$

We want to know how the variable associated with a nomogram changes due to an increment of load at each pnode. For a generation group nomogram variable this can be written as follows:

$$SF^{node}_{nm,nv} = \frac{\Delta V^{t}_{nm,nv}}{\Delta P_{node}} = 0$$

There is a subtlety to note here. The subtlety is that an incremental injection at this pnode is not assumed to come from the portion of a generation group that may reside at this pnode. Since the nomogram variable depends only on the generation group resources and not on a general injection at the pnode then the nomogram variable does not change. In particular, if the incremental change in injection at the pnode was actually an increment in load at the pnode the generation group nomogram variable would not change and therefore the shift factor term is zero.

Nomogram Segment Equation

For every segment of the active curve for each nomogram for each time period an equation should be added to the model. This section will discuss the form of the equation to be added.

$$a_1^{nm,nc,ns} \cdot V_{nm,1}^t + a_2^{nm,nc,ns} \cdot V_{nm,2}^t + ... + a_n^{nm,nc,ns} \cdot V_{nm,n}^t \le b^{nm,nc,ns}; \quad nm \in NM; ns \in NMS_{nm,nc}; t \in T$$

This can be written in a more compact notation as follows:

$$\sum_{nv \in NMV_{nm}} a_{nv}^{nm,nc,ns} \cdot V_{nm,nv}^t \le b^{nm,nc,ns}; \quad nm \in NM; ns = \in NMS_{nm,nc}; t \in T$$

There are several observations to be made here. First, according to the table definitions, the equation can be one of the following relationships: $\le, =, \ge$. The equation above used $\le$ for convenience sake. Second the number of equations being described here should not be missed. The form shown above looks pretty simple however the total number of equations represented is given by

$$NumEqs = T \cdot \sum_{nm \in NM} NMS_{nm,nc}$$

An infeasibility slack variable should be included in the nomogram segment inequality constraint. This is similar to the slack variable processing that is done for other constraints. In particular this has the following form:

$$\sum_{nv \in NMV_{nm}} a_{nv}^{nm,nc,ns} \cdot V_{nm,nv}^t \le b^{nm,nc,ns} + \overline{P}_{nm,nc,ns}^{viol,t}; \quad nm \in NM; ns = \in NMS_{nm,nc}; t \in T$$

The infeasibility slack variable should be a non-negative value, i.e.,

$$\overline{P}_{nm,nc,ns}^{viol,t} \ge 0; \quad nm \in NM; ns \in NMS_{nm,nc}; t \in T$$

There is a penalty function associated with the infeasibility slack variable. This penalty function needs to be included as part of the objective function.

$$C(\overline{P}_{nm,nc,ns}^{viol;t}) = p_{NM}^{viol} \cdot \overline{P}_{nm,nc,ns}^{viol;t}; \quad p_{NM}^{viol} >> 1$$

It should be remembered that the nomogram segment constraint be any one of the types $\le, =, \ge$. The exact form of the infeasibility slack variable term will depend on the specific form being used.

Following the solution, the nomogram segments that are binding will provide a contribution to the congestion component of the LMP for every price node. Let us consider this contribution in more detail here. First let us consider the equation for LMP values without any contribution from nomograms, namely:

$$LMP_{node}^{En;t} = MCP^{En;t} / pf_{node}^t + \sum_{line \in LL} SF_{line}^{node} \cdot TCP_{line}^t$$

Where the index *node* refers to every price node. If we extend this to include the effect of nomograms we can write

$$LMP_{node}^{En;t} = MCP^{En;t} / pf_{node}^t + \sum_{line \in LL} SF_{line}^{node} \cdot TCP_{line}^t + \sum_{nm \in NM} \sum_{ns \in NMS_{nm,nc}} SF_{nm,nc,ns}^{node} \cdot NSCP_{nm,nc,ns}^t$$

The nomogram segment shadow price $NSCP_{nm,nc,ns}^t$ will be a byproduct of the optimization. Let us turn our attention to how to determine the term $SF_{nm,nc,ns}^{node}$. This can be written as follows:

$$SF_{nm,nc,ns}^{node} = \sum_{nv \in NMV_{nm}} a_{nv}^{nm,nc,ns} \cdot SF_{nm,nv}^{node}$$

Where as described in the previous section:

$$SF_{nm,nv}^{node} = \begin{cases} SF_{ntc}^{node} & \text{if } nv \text{ is transmission corridor } ntc \text{ flow} \\ 0 & \text{if } nv \text{ is an aggregate generating resource output} \end{cases}$$

Specifically for Aggregate Generating Resources that are variables in a given nomogram, an additional marginal congestion component contribution exists because of the restriction that that particular nomogram imposes on the Aggregate Generating Resource:

$$LMP_{V_{nm,nv}}^{En;t} = MCP^{En;t} / pf_{node}^{t} + \sum_{line \in LL} SF_{line}^{node} \cdot TCP_{line}^{t} + \sum_{ns \in NMS_{nm,nc}} a_{nv}^{nm,nc,ns} \cdot NSCP_{nm,nc,ns}^{t}$$

Where the node is the aggregate node (ANode) of the aggregate generating resource and the shift factor is the aggregate shift factor that corresponds to that aggregate node.

Note that this additional marginal congestion component applies only to the Aggregate Generating Resources that are variables in a nomogram; it does not apply to other resources, even if connected to the same node(s).

Impact on nodal prices

As stated in the ISO's Managing Full Network Model (FNM) Business Practice Manual[27], "The operation of the ISO's Markets, which includes the determination and mitigation of transmission congestion and the calculation of LMPs, requires a network model [Full Network Model] that provides a detailed and accurate representation of the power system included in the ISO Markets."

The FNM is composed of network connectivity Nodes[28] (CNodes) interconnected with network branches. A CNode represents a connection point used to define the physical topological connectivity of the network where only one load or generation device can be connected to a CNode. Each terminal of equipment is connected to a CNode. Each piece of equipment has a CNode associated with it and roles up into a bus which represents all the topological nodes associated with a generating resource. Below in Figure 1, the grey circle represents generator 1 (G1)'s physical topological connection point of the terminal of the equipment to a network node, the connectivity node (CNode). In this example, there is only one piece of equipment which is connected to a CNode so the CNode and bus are the same.

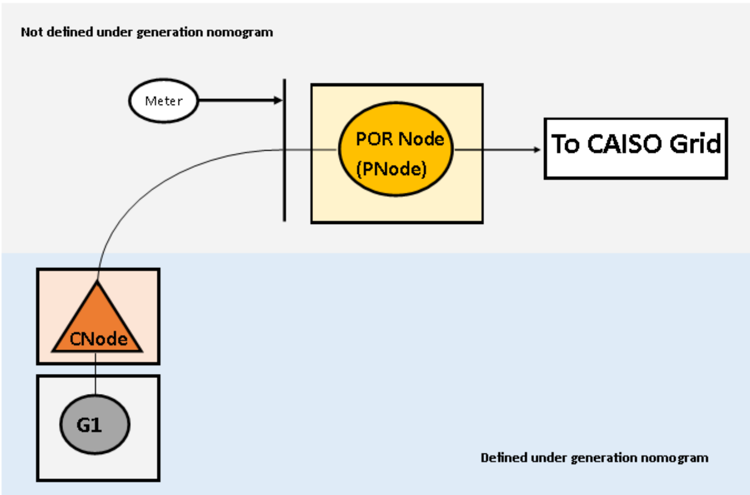
Figure 1 further shows the connection between the CNode to the Pricing Node (PNode), which represents the point at which the injection is received into the ISO Controlled Grid for Supply, or withdrawal is delivered out of the ISO Controlled Grid for Demand. Generally, the PNode of a generating unit will coincide with the CNode where the relevant revenue quality meter is connected or compensated, to reflect the point at which the Generating Units are connected to

[27] Available on Page 11 at https://bpmcm.caiso.com/BPM%20Document%20Library/Managing%20Full%20Network%20Model/Managing%20Full%20Network%20Model%20BPM%20Version%208_clean.docx.

[28] The ISO BPMs have adopted "Connectivity Node" or CNode as an alternative expression of "Node".

the ISO Balancing Authority Area. This Location is referred to as the “Point Of Receipt” (POR) and is considered to be a PNode. However, the PNode and CNode can differ in the FNM.

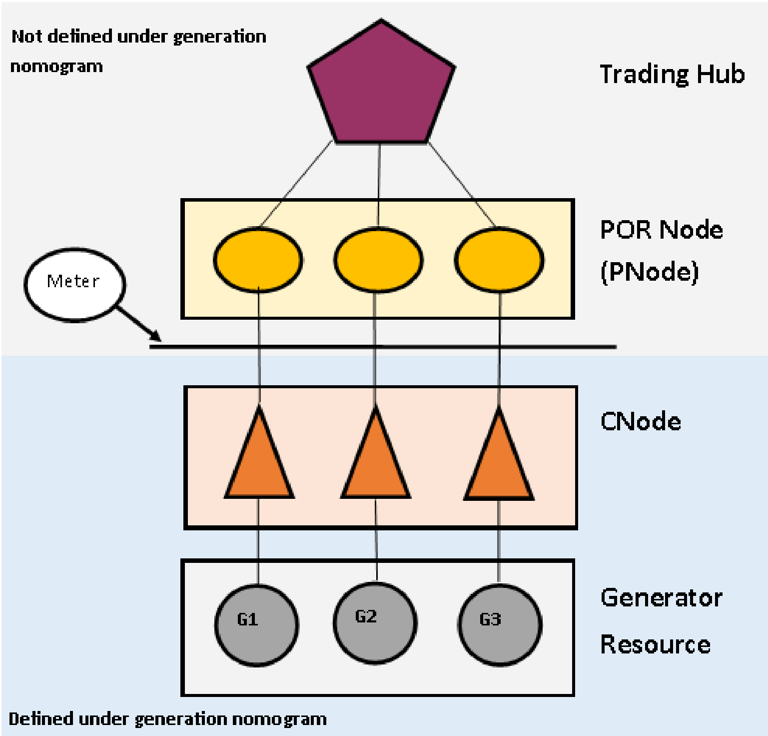
Figure 1: Simple generating unit with one CNode and Pnode



The diagram shows the pieces of the FNM that would be variables under the generation group nomogram where the nodes in the blue box would be defined as variable and the nodes in the grey box would not be defined as variable under the generation group nomogram. While the nomogram segment shadow price is a natural byproduct of the optimization, the shift factor indicating how the nomogram variable nv of nomogram nm changes due to an incremental injection into the system at the PNode location node ($SF_{nm,nv}^{node}$) is 0 so that the PNode LMP does not contain the nomogram segment shadow price. Whereas, the shift factor indicating how the nomogram variable nv of nomogram nm changes due to an incremental injection into the system at the CNode location node ($SF_{nm,nv}^{node}$) is 1 so that the CNode LMP associated with each element of the nomogram does contain the nomogram segment shadow price.

As another example, any transactions settling off of a trading hub would contain the price information from the Pnodes that are aggregated into the aggregated pricing node (APNode) also called Trading Hub. Figure 2 shows the relationship between the generators (grey circles), CNodes (orange triangles) to the PNodes that are aggregated into the Trading Hub's APNode.

Figure 2: Relationship of nodes to aggregate pricing nodes



The diagram shows the pieces of the FNM that would be variables under the generation group nomogram where the nodes in the blue box would be defined as variable and the nodes in the grey box would not be defined as variable under the generation group nomogram. As shown in Figure 2 only the CNodes are variables under the generation group nomogram so that only the impact of the nomogram segment shadow price is reflected in the CNode LMP whereby the shift factor to the PNodes, shown in the grey box, is 0 and the shadow price is not captured in these prices. Because the shadow price is not captured in the PNode LMPs, the impact of the shadow price does not get reflected in the APNodes either since they are based on PNode LMPs.

Appendix B: Technical appendix on market measures

The GPI formulation just for the SCE and SDGE fuel regions[29]. There will be scalars applied to the commodity price (relevant next day gas index) to get to a different GPI for energy versus commitment cost estimates. Every other fuel region will remain unaffected and the gas price indices are the same for commitment costs and default energy bid calculation (i.e. $GPI_{Commitment} = GPI_{Energy}$). These scalars would be used to formulate the two different GPIs for the SoCalGas and SDG&E fuel regions every day. If adjusted up or down there would be a market notice specifying the new scalars.

Equation 4: GPI Formulation

$$GPI_{Commitment} = (Commodity\ Price * \text{Scalar}_{Commitment}) + Transportation\ Rate$$

$$GPI_{Energy} = (Commodity\ Price * \text{Scalar}_{DEB}) + Transportation\ Rate$$

Where:

$\text{Scalar}_{Commitment} = 1.75$, Fuel Region is eligible for scalar

$\text{Scalar}_{DEB} = 1.25$, Fuel Region is eligible for scalar

In the following cost estimate equations, the ISO highlights the portion of the calculations affected and clarifies which GPI is used for which cost estimate.[30]

Equation 5: Proxy Start-Up Costs

Start-up Cost

$$= \begin{cases} \text{Start-up Fuel Cost} + \text{Start-up Energy Cost} + \text{GMC Adder}, & GHG_{COMPLIANCE} =' N' and\ MMA = 0 \\ \text{Start-up Fuel Cost} + \text{Start-up Energy Cost} + \text{GMC Adder} + \text{GHG Cost}, & GHG_{COMPLIANCE} =' Y' and\ MMA = 0 \\ \text{Start-up Fuel Cost} + \text{Start-up Energy Cost} + \text{GMC Adder} + \text{GHG Cost} + MMA, & GHG_{COMPLIANCE} =' Y' and\ MMA \neq 0 \end{cases}$$

Where:

$\text{Start-up Fuel Cost} = STRT\_STARTUP\_FUEL * GPI_{Commitment}$
$\text{Start-up Energy Cost} = STRT\_STARTUP\_AUX * EPI$

$$\text{GMC Adder} = Pmin * (STARTUP\_RAMP\_TIME/60min) * \frac{GMC}{2}$$

$\text{GHG Cost} = STRT\_STARTUP\_FUEL * \text{Emissions Rate} * \text{GHG Allowance Rate}$

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[29] This scope item could be applied in future fuel region's GPI formulation only if the pipeline transport company is defined as Southern California Gas & Electric.
[30] The equation for transition costs is not included but the $GPI_{Commitment}$ would be used to determine the proxy transition cost estimate. Further, the $GPI_{Commitment}$

Equation 6: Proxy Minimum Load Costs

Minimum Load Cost

$$= \begin{cases} \text{Minimum Load Fuel Cost} + \text{VOM} + \text{GMC Adder}\,, & GHG_{COMPLIANCE} =' N' and\ MMA = 0 \\ \text{Minimum Load Fuel Cost} + \text{VOM} + \text{GMC Adder} + \text{GHG Cost}\,, & GHG_{COMPLIANCE} =' Y' and\ MMA = 0 \\ \text{Minimum Load Fuel Cost} + \text{VOM} + \text{GMC Adder} + \text{GHG Cost} + MMA\,, & GHG_{COMPLIANCE} =' Y' and\ MMA \neq 0 \end{cases}$$

Where:

$\text{Minimum Load Fuel Cost} = Unit\ Conversion * \text{Heat\_Rate} * Pmin * GPI_{Commitment}$

$\text{VOM} = \text{VOM} * \text{Pmin}$
$\text{GMC Adder} = Pmin * GMC$

$\text{GHG Cost} = Unit\ Conversion * \text{Heat\_Rate} * Pmin * \text{Emissions Rate} * \text{GHG Allowance Rate}$

Equation 7: Default Energy Bid Costs

Default Energy Bid Cost

$$= \begin{cases} (\text{Segment's Fuel Cost} + \text{VOM} + \text{GMC Adder}) * Scalar, & GHG_{COMPLIANCE} =' N' and\ DEBA = 0 \\ (\text{Segment's Fuel Cost} + \text{VOM} + \text{GMC Adder} + \text{GHG Cost}\,) * Scalar, & GHG_{COMPLIANCE} =' Y' and\ DEBA = 0 \\ (\text{Segment's Fuel Cost} + \text{VOM} + \text{GMC Adder} + \text{GHG Cost} + DEBA) * Scalar\,, & GHG_{COMPLIANCE} =' Y' and\ DEBA \neq 0 \end{cases}$$

Where:

$\text{Individual Segment's Fuel Cost} = Unit\ Conversion * \text{Heat\_Rate} * GPI_{Energy}$

$\text{GHG Cost} = Unit\ Conversion * \text{Heat\_Rate} * \text{Emissions Rate} * \text{GHG Allowance Rate}$

$\text{Scalar} = 1.1$