November 2, 2020

Regulatory Commission of Alaska
701 W. 8th Avenue, Suite 300
Anchorage, AK 99501

Re: R-20-002

Dear Commissioners:

Renewable Energy Alaska Project (REAP) respectfully submits the following comments in response to the Questions discussed at the RCA Technical Conference on R-20-002 held on October 21-22, 2020. These comments follow the sequence of the Questions that the Commission reviewed in that Technical Conference.

Integrated Resource Planning
Minimum Elements in an IRP Filing

1) **What criteria should be required in the IRP when filed with the Commission?**

REAP supports Option #1 from the October 21-22 Technical Conference: *Regulations state a comprehensive list of criteria that an IRP must contain at the time of filing.*

Option #1 is consistent with the requirements used by best practice states such as Arizona, Colorado, and Oregon cited by the Regulatory Assistance Project (RAP) in Best Practices in Electric Utility Integrated Resource Planning.

The Arizona Administrative Code includes a number of similar requirements as Option #1 such as reporting requirements, review of resource plans, procurement, and independent monitor selections and responsibilities.[1] The Public Utility Commission of Oregon also provides extensive guidelines for the IRP process, including an explanation of the procedural requirements, analysis of high and low load growth scenarios, identification of capacity and energy needs, estimations of costs for supply and demand-side resource options, identification of key assumptions about the future, analysis of uncertainties for each portfolio, etc. [2]

By including what is required in statute, the RCA provides guidance to the ERO on what its task is, and the RCA establishes metrics it can use to determine whether the Integrated

[1] Arizona Administrative Code Title 14, Chapter 2, Article 7 https://apps.azsos.gov/public_services/Title_14/14-02.pdf
[2] Public Utility Commission of Oregon. Order No. 07-002, https://apps.puc.state.or.us/orders/2007ords/07-047.pdf

Resource Plan (IRP) has been adequately completed. REAP also agrees with RAP that "Integrated resource planning rules be reexamined periodically, to make sure they reflect the current conditions and challenges associated with providing reliable electric service at reasonable costs". [3]

In addition to the items listed in Option #1, REAP would suggest adding:

1) The addition of a stakeholder process that ensures that the public is included in the IRP process in its very early stages. An example is the process adopted by the Arizona Public Service (APS), Arizona's largest utility. This includes a series of public workshops during the process. APS has also contracted with the Morrison Institute at Arizona State University to conduct a series of four "Informed Perception Project" surveys on customer preferences and concerns regarding the energy resource options available to APS.[4] It is important that public get a first bite at the apple and that, in an informal setting, they get to respond to the proposal. This will be useful to the ERO and RCA, because the public will be another entity enlisted to identify shortcomings and point out strengths in draft plans before the ERO starts its work in earnest. This process could be inserted under (2)(B) and/or (9)(e). The current list of IRP criteria in Option #1 does not adequately address public involvement in the IRP process.
2) Under section (6) addressing *identification of resource options*, rules that mandate that the ERO consider all feasible supply-side, demand-side, and transmission resources that are expected to be available within the specified planning period.
3) Under section (6) addressing *identification of resource options*, the addition of carbon pricing as part of the consideration of fuel price risk.
4) Under section (6) addressing *identification of resource options* the addition of state and federal subsidies as part of the consideration of fuel price risk.
5) Under section (6) addressing *identification of resource options*, the requirement that the ERO consider the value of any ancillary services that a resource may provide.
6) Under section (6) addressing *identification of resource options*, the requirement that the ERO consider the requirements in local, state and national legislation.
7) Under section (6) addressing *identification of resource options*, the requirement that the ERO consider the value of portfolio diversity and regional energy security.
8) Under section (3)(f) addressing the *list of data sources*, the requirement that the ERO describe the database it will be using, including criteria that describe why any data will not be publicly accessible.

[3] Best Practices in Electric Utility Integrated Resource Planning. Regulatory Assistance Project, 2013, page 26.
[4] Best Practices in Electric Utility Integrated Resource Planning. Regulatory Assistance Project, 2013, page 16.

In addition, under section (9)(f) addressing procedures and timing for implementing resource changes including resource RFPs, and based on the lively discussion on these matters at the October 21-22 Technical Conference, **REAP would like to formally request another, short Technical Conference to continue that important discussion on the discrete question of how the Railbelt will get from plans to the construction/acquisition of resources.** REAP does not believe the discussion at the Technical Conference left participants with a sufficiently clear view of how projects (or needs) identified in the IRP will move toward construction. REAP also believes that the subject brings up the important concept of cost allocation for generation projects that are identified in the plan to have *regional* benefit.

While the utilities have generally indicated that they would like to see planning guided by reliability standards, REAP believes that the Commission should adopt regulations that ensure that many other factors must be considered by the ERO, and given due weight. Indeed, even on reliability standards, REAP believes that the fast pace of technology change and a world-wide movement to de-carbonization[5] through energy storage and intermittent power from wind and solar necessitates that the ERO continually rethink how reliability can be met with 21st century technology. Even without climate change and carbon emissions as a driver, renewable energy will continue to decrease in price, as it has over the last few decades. Wind and solar are already the cheapest power sources on an unsubsidized, levelized cost of energy basis.[6] As energy storage continues to decrease in price, wind and solar will gain the dispatch characteristics and associated benefits, of conventional generation resources.

Similarly, rapid gains in demand-side management strategies and technologies will require that the IRP process consider those less expensive options to meet demand first.

In contrast, the lack of regional planning by the six Railbelt utilities over the last two decades has led to a regional over-investment in generation and underinvestment in transmission and demand side management. Even more concerning for Railbelt consumers and the region's carbon budget, the generation technology that most utilities have chosen to pin the Railbelt's future on relies heavily on natural gas. That gas is now provided primarily by just one producer, Hillcorp, in a market that is relatively tiny compared to the gas reserves in Cook Inlet. Indeed, the large majority of natural gas ever

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[5] China's pledge to become carbon neural before 2060. https://www.theguardian.com/environment/2020/sep/22/china-pledges-to-reach-carbon-neutrality-before-2060
Japan's pledge to become carbon neutral by 2050. https://www.economist.com/asia/2020/10/29/japan-promises-to-be-carbon-neutral-by-2050
European Union's pledge to become carbon neutral by 2050.
https://ec.europa.eu/commission/presscorner/detail/en/ip_20_335
U.S. States which now have 100% renewable or carbon neutral legislation by or before mid-century.
https://www.americanprogress.org/issues/green/reports/2020/04/30/484163/states-laying-road-map-climate-leadership/
[6] Levelized Cost of Energy and Levelized Cost of Storage – 2020. Lazard. October 2020.
https://www.lazard.com/perspective/levelized-cost-of-energy-and-levelized-cost-of-storage-2020/

produced in Cook Inlet went to two anchor tenants in the region that are now gone – the LNG export facility and the Agrium fertilizer plant on the Kenai Peninsula. Furthermore, the hundreds of millions of dollars of state subsidies that have been provided to incentivize production in Cook Inlet are disappearing as the state's budget problems continue to worsen. The result is that utilities are now paying more than three times what Lower 48 utilities are paying for natural gas and the Railbelt is more than 80% dependent on that high-priced gas.

IRP Development Criteria

2. **Should regulations require non-supply side measures, such as demand side management measures and distributed energy resources, be evaluated in addition to traditional supply side measures for meeting load?**

REAP supports Option #3 from the October 21-22 Technical Conference: *Regulations specify what demand side management measure must be included for consideration, such as distributed energy resources, energy efficiency programs, load-shifting programs, etc.*

This requirement is consistent with SB 123, which states that, "An integrated resource plan must contain an evaluation of the full range of cost-effective means for load-serving entities to meet the service requirements of all customers, including additional generation, transmission, *battery storage, and conservation or similar improvements in efficiency* (emphasis added)".[7]

REAP believes these measures (and possibly others) should be listed in the regulations, with additional language describing the list such as "included, but not limited to" to broaden the definition and to give the ERO flexibility to consider other measures. Including an explicit list provides a baseline of the most commonly used demand-side measures that the ERO must at least consider. A detailed list is consistent with practice in Colorado, which requires that "[e]ach ten-year transmission plan shall contain…The load forecast reductions arising from net metered distributed generation and utility sponsored energy efficiency programs, and controllable demand side management data including the interruptible demands and direct load control management used to develop the transmission." [8]

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[7] 42.05.780 (a)

[8] 4 CCR 723-3 page 104 and 105
https://www.sos.state.co.us/CCR/GenerateRulePdf.do?ruleVersionId=6403&fileName=4%20CCR%20723-3

Other states necessitate that "all" demand-side resources be considered. These include Delaware where "generation, transmission and Demand-Side Management programs"[9] must be evaluated. Additionally, Indiana requires that "a detailed explanation of the assessment of demand-side and supply-side resources" must be included in the IRP.[10]

REAP also believes regulations should require the IRP to include a short narrative on how each of the demand-side measures listed in regulation were considered in the process, and if they are not included in a preferred portfolio, why.

3) Should regulations ensure technology neutrality and network adequacy with regards to IRP development?

REAP believes that technology neutrality and network adequacy are implied in SB 123, subject to language in the statute that requires the IRP to describe a portfolio that has the greatest value in the public interest. All feasible generation, transmission and demand-side options should be investigated (see Question #1, Addition #2, above).

Since REAP believes that Alaska state energy policy in AS 44.99.115 should be part of the analysis of "greatest value", Option #3 comes closest to what REAP would suggest be in regulation.

4) Should regulations incorporate existing State Energy Policy into the ERO IRP development and Large Project Preapproval process?

As REAP notes throughout these comments, the definition of "greatest value in the public interest" should include a consideration of local ordinances and regulations, state law and regulations and federal law and regulations. Therefore, **Option #2 from the October 21-22 Technical Conference is closest** to what REAP would support. REAP believes consideration of local, state and national law must be a criteria for the adequacy of an IRP.

Forecast Methodology

5) Should regulations require that the methods for estimating future demand be uniform

[9] HB 6, the Delaware Electric Utility Retail Customer Supply Act of 2006 https://legis.delaware.gov/BillDetail/15602

[10] 170 Indiana Administrative Code 4-7-Guidelines for Integrated Resource Planning by an Electric Utility, Section 170 IAC 4-7-7 – Integrated resource plan contents https://casetext.com/regulation/indiana-administrative-code/title-170-indiana-utility-regulatory-commission/article-4-electric-utilities/rule-170-iac-4-7-guidelines-for-integrated-resource-planning-by-an-electric-utility/section-170-iac-4-7-4-integrated-resource-plan-contents

across all load serving entities in an interconnected electrical network? If not, then why not? If so, then what methodology is recommended?

REAP supports Option #2 from the October 21-22 Technical Conference. Without uniformity, the work of the ERO will be made more difficult. This question presumes that demand forecasts from each of the Load Serving Entities in the region will be aggregated by the ERO. The demand forecast in the IRP for the entire interconnected bulk power system *could theoretically* aggregate demand forecasts from each of the respective LSEs, but this would only work if each LSE was using the same methodologies to measure the same sensitivities, such as size *and shape* of consumer demand, commercial demand, industrial demand, transportation demand, heating demand, et cetera. For an aggregated demand forecast to be useful, each LSE must use all of the same measuring tools, and use the same assumptions. If indeed the question does presume aggregating individual LSE's demand forecasts for the IRP, REAP also believes that the ERO should be required to use an independent third party consultant to test and determine whether all methodologies are indeed consistent.

REAP believes that the regulations can be written to require that each ERO in the state use a consistent methodology without requiring that every ERO use the same methodology.

Since all LSEs will be subject to the same reliability standards, different standards in different parts of the Railbelt should not impact forecasting methodologies.

6) Considering shifting market demand curves, beneficial electrification, and demand-side resources, how should the IRP process determine or discover what energy services customers want and need and what they are willing to pay for them?

REAP supports Option #2 from the October 21-22 Technical Conference: *Regulations require the ERO to address how potential consumer responses to price signals, new government policies, or penetration of new technologies that affect demand will be discovered and measured during the forecast period so that subsequent forecasts can be improved.*

REAP believes that beneficial electrification (e.g. electric transportation) and distributed energy resources (e.g. rooftop solar) could both impact the demand for electricity in differing ways. That shifting consumer demand will definitely have an impact on load forecasting in the planning process. Shifting customer interests will also have an impact on the price that consumers are willing to pay for a service. Furthermore, the Railbelt also has no experience with time-of-use rate structures and other demand-side management measures that are becoming more commonly used in other parts of the country. For all these reasons, REAP believes it will be important for the IRP process to gather as much information as possible from consumers within each ERO. Compared to even 25 years ago when expensive mail or phone expensive surveys had to used, today information is much easier to collect and collate using the internet. It is also easier and cheaper to store information electronically.

Research demonstrates that consumers increasingly expect more from their utilities than simple reliability. A recent Utility Dive article notes that today's consumers are looking for at least three things from their utility: 1) more renewable energy investments; 2) more data and 3) choices when it comes to peak shifting programs.[11] This shift to consumer-driven energy was also highlighted by MorganStanley research in 2019 that found that "one-in-three homeowners worldwide are now interested in generating their own electricity within the next five years."[12] One excellent example of a utility that offers a wide range of innovative programs to its customers, communicates constantly about them with those customers and makes those programs and communications a part of its integrated resource planning is Vermont's Green Mountain Power.[13]

Draft regulatory language could include a requirement that an ERO, as part of the IRP process, communicate with all customers within the interconnected bulk power system that the ERO serves to inquire:

1) What services and programs customers expect from their respective utilities.
2) What services and programs that customers would take advantage of *if* their utility offered them, with examples that could include net metering, time-of-use and other peak-shifting rates and utility pilot programs to install home energy storage, remotely accessible hot water heaters, ductless heat pumps and electric vehicle charging stations.

Regulations could also require the ERO to include in the IRP the various methods it used to communicate with customer, and the frequency of those communications.

Processes

7) How frequently should IRPs be filed, and what minimum Forecast Period should an IRP cover?

- **Date of Initial Filing**

REAP supports Option #2 from the October 21-22 Technical Conference: *Regulations set the date for filing the initial IRP within two (2) years after the ERO is certificated.*

[11] Utility Dive, Durand, April 10, 2018
[12] MorganStanley, October 7, 2019. https://www.morganstanley.com/ideas/consumer-generated-electricity
[13] Green Mountain Power 2018 IRP, https://greenmountainpower.com/wp-content/uploads/2019/03/IRP-Innovative-Customer-Programs.pdf

REAP believes that while this may an ambitious schedule, the Railbelt grid is in great need of a plan, and the sooner it is developed, the better. Regulations could allow an ERO extra time with a finding of good cause by the Commission. REAP does not believe the Black & Veatch regional Railbelt IRP completed in 2010 took more than 18 months.

- **Frequency of Filing**

REAP supports Option #2 from the October 21-22 Technical Conference: *Regulations require that every three (3) years after initially filing its IRP, an ERO shall submit an updated plan covering the Forecast Period.*

The vast majority of states that do integrated resource planning require plans to be updated every two or three years.[14] REAP does not believe that updating an initial plan every three years is too onerous, or will be too expensive. With costs spread out over the entire rate base of the Railbelt, the cost to each individual ratepayer every three years will be not be great. Railbelt utilities also stated at the Technical Conference that they are already doing planning for themselves. If the information that each utility is now collecting can be acquired in a uniform way, we should be able to presume that the work of the ERO will be lessened when it has to develop a plan for the entire region every three years. Utilities also stated on several occasions that most generation projects require a much longer lead time than three years, thus making it very unlikely that a large generation or transmission project will ever need special pre-approval between each three-year window between plans. The benefits of frequent planning intervals include:

1) Capturing shifting consumer demand;
2) Re-evaluating demand side management opportunities;
3) Re-evaluating new local, state or national legislation that can impact the electrical system;
4) Re-evaluating renewable technologies that continually get less expensive and;
5) Helping to ensure that plans do not become stale. A recent IRP will help the Commission make decisions if for some unlikely reason a project proponent comes to the RCA between IRPs for special project pre-approval that must be consistent with the most recent plan.

- **Forecast Period**

REAP supports Option #4 from the October 21-22 Technical Conference: *Regulations provide for multiple Forecast Periods, one short term (e.g., five (5) years) and one long term.*

[14] Best Practices in Electric Utility Integrated Resource Planning. Regulatory Assistance Project, 2013, page 6.

REAP believes that a shorter, five-year forecast period is the time period on which decisions to acquire new assets should be made. However, REAP believes the IRP should also attempt to forecast demand and supply options out for 20 years.[15]

8) In order to develop an IRP, data-sharing will be crucial. Should regulations require or encourage a shared and transparent database as an integral part of the IRP process? If so, how would this be accomplished?

REAP supports Option #2 from the October 21-22 Technical Conference: *Regulations require the ERO to manage a common database for shared information.*

REAP believes a shared, transparent database is consistent with requiring a shared load forecasting methodology (Question #5 above). REAP is concerned that a common database will not be developed and/or used if it is not required in regulation.

REAP understands that some information may need to kept from the public for security reasons. The burden should be on each utility to justify the confidentiality of data. However, meaningful data sharing and a public database that contains consistently gathered information will help researchers and modelers, will create much-needed transparency and will make each IRP a richer process. REAP does not have a suggestion for a data platform. All information should be retained for 50 years.

9) Public notice and process requirements at both the ERO and agency level.

As noted above under Question #1, REAP believes that the regulations should provide for meaningful public input at the *front end* of the IRP process. Other states require more extensive public participation in the IRP process than is currently being contemplated here. An example is the process adopted by the Arizona Public Service (APS), Arizona's largest utility. This includes a series of public workshops during the process. APS has also contracted with the Morrison Institute at Arizona State University to conduct a series of four "Informed Perception Project" surveys on customer preferences and concerns regarding the energy resource options available to APS.[16] The Arizona Corporation Commission (ACC) requires that "an outline of the timing and extent of public participation and advisory group meetings the load-serving entity intends to hold before completing and filing the resource plan."[17] In Oregon, the PUC that the public "should be allowed significant involvement in the preparation of the IRP.

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[15]The most common IRP planning horizons span a 20-year period. Best Practices in Electric Utility Integrated Resource Planning. Regulatory Assistance Project, 2013, page 6.
[16] Best Practices in Electric Utility Integrated Resource Planning. Regulatory Assistance Project, 2013, page 16.

[17] Arizona Corporation Commission. Decision No. 71722. Docket No. RE-00000A-09-0249. June 3, 2010. Page 18. https://docket.images.azcc.gov/0000112475.pdf

Involvement includes opportunities to contribute information and ideas, as well as to receive information."[18] The PUC goes on to outline public notice and procedural requirements under Guidelines 2 and 3.

Question #9 is silent as to how the public would weigh-in with the Commission on the adequacy of the IRP.

10) What criteria for Commission review of the process used to develop the IRP at the ERO level?

As noted in Questions #1 and #9 above, REAP believes that the IRP process should include opportunities for the public to weigh-in at all stages. This is **somewhat consistent with Option #6** from the October 21-22 Technical Conference: *Regulations state there will be a process to ensure the IRP process will be vetted by a robust stakeholder process.*

REAP strongly believes that the IRP *process* should be one of the criteria used by the Commission to determine whether an IRP should be approved or returned for modification, the subject of Question #16. That is, if required public process is not followed by the ERO, it could be grounds for not approving the IRP.

If the Commission articulates in regulation what the public process at the front-end (e.g., public workshops and focus groups) and conclusion of the process (e.g., public opportunity to weigh-in on IRP submitted to the Commission) then whether those requirements have been followed should be part of the Commission review when evaluating the public process associated with the IRP.

11) Should regulations clarify the boundaries, if any, for appropriate cost recovery of the approved IRP?

During the October 21-22 Technical Conference there appeared to be some confusion among participants as to whether this question related to cost recovery for the IRP process, or cost recovery for the projects that are part of the preferred portfolio and/or action plan of the IRP. This led to the question of how the IRP will translate into acquisition of assets that are part of the preferred portfolio and/or action plan.

[18] Public Utility Commission of Oregon. Order No. 07-002. Docket No. UM 1056. January 8, 2007. Page 8

If question #11 does refer to the allocation of costs for assets acquired, as the Options suggest, REAP believes there must be more clarity on the process of moving from IRP to acquisition (plan to projects) before REAP could suggest an option. Depending on that implementation process, REAP believes there are many questions still to be answered, including:

1) Will there be a procurement process that requests proposals from load serving entities, independent power producers and others to determine the lowest *actual* cost of an asset? Colorado includes such a procurement process in its integrated resource planning.[19]
2) If there is no procurement process, how does the IRP avoid a self-build bias?
3) Will an IRP ever simply identify a need (e.g., 30 MWs of baseload generation) or does the IRP have to be more specific about the location and type of project for any reasonable evaluation of its cost and benefits to be a part of the IRP?
4) What entity will finance, construct, own and operate projects that have *regional value* (related to Option #4)?
5) What criteria will determine *regional value?* Should there be any preferential weight given regional projects? How can regional value be determined without a system of regional economic dispatch?
6) Will the Commission or the ERO develop cost recovery mechanisms for generation projects or demand-side management acquisitions that have regional value?
7) What will the criteria for such cost recovery be?
8) Does implicit IRP approval of a project in a particular load serving area guarantee cost recovery by the builder/owner of the project? What if there are cost overruns because of construction delays? (related to Options #2 and #3)?
9) Will implicit approval of a project in an IRP result in a *Notice to Construct*?
10) What if a utility serving an area does not want to build a project identified in IRP's preferred portfolio and/or action plan, arguing it is *not needed*?
11) How does the current lack of a regional transmission tariff impact the process?
12) Should the IRP include an Action Plan if it is only aspirational?
13) Are these questions for the ERO tariff? If so, do they have to be answered when the RRC applies to become the ERO?

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[19] Colorado Senate Bill 19-236 Subsection (5)(b) Page 17
https://leg.colorado.gov/sites/default/files/documents/2019A/bills/2019a_236_rer.pdf

REAP does not believe the discussion of Question #11 at the October 21-22 Technical Conference was clearly answered these questions. For that reason, **REAP would respectfully request that the Commission hold another Technical Conference** to address the questions posed here, as well as related questions that other participants may have.

12) Should cost recovery achieved through ERO surcharge mechanisms be in addition to separate individual utility tariffs?

REAP believes that the answer to this question is related to the questions posed by Question #11 above and would respectfully suggest that this discrete question be added to any additional Technical Conference.

REAP would comment that it may be consistent with SB 123 for the ERO to develop cost recovery mechanisms for asset acquisitions besides transmission, which SB 123 already requires. There is some implication in Option #3 that there will be the need to allocate costs of regional projects. But Option #3 seems to ask whether the Commission, not the ERO, should develop such cost recovery.

13) How should the IRP process incorporate prices, incentives, and market mechanisms?

From REAP's perspective, Question #13 tends to conflate the question about how a region gets from an IRP to acquisition of assets that REAP discussed above in Question #11 and #12, and the demand discovery and related issues addressed above in Question #6.

Market mechanisms, such as a procurement process, will help the IRP determine a more accurate *price* of asset acquisitions.

Incentives are more related to the pilot programs that individual utilities may offer that REAP highlighted in its response to Question #6. Those incentives could help either lower load (efficiency and peak-shifting rate programs) or increase load (electric vehicle and heat pump incentive programs).

If demand discovery and consideration of a range of means to accurately forecast changing consumer demand is going to be required then, as Option #2 states, regulations should "provide that market opportunities and financial incentives" should be considered in the development and evaluation of IRPs". In other words, utility incentive programs could be part of the preferred portfolio and/or action plan of an IRP. Utilities should be required to demonstrate how they are working with customers to incentivize the efficient use of energy, both at the household level (e.g., a program for customers to acquire energy efficient freezers) and the network level (e.g., a program to allow customers to be paid by the utility to allow the utility to turn off those same freezers to shave peaks and avoid having to turn on expensive generation assets). It would be useful to have requirements that load serving entities present options for incentivizing and fairly compensating flexible loads, at the customers' discretion. This would provide the value of smoothing aggregate network capacity requirements in order to minimize the need for *new* network investments, as well as optimizing the value of the network assets already in the ground.

Similarly, if the IRP process is going to spell-out more clearly the path from plan to project, then REAP would argue that some type of procurement process to determine the best "prices" (also taken from Option #2) for a particular asset acquisition should also be required in regulation.

Commission Criteria in the Evaluation of an IRP

14) Should regulations specify the phrase "greatest value, consistent with the load serving entities' obligations"? If not, then why not? If so, then what aspects of "value" should regulations specifically accommodate? Should regulations delineate a load-serving entity's obligations?

REAP believes that the "greatest value, consistent with the load serving entities' obligations" can already be determined from the language of SB 123. REAP believes it means "greatest value, consistent with the public interest*"*[20] and consistent with the load serving entities' obligations. Those obligations of load-serving entities are clearly defined in AS 42.05.772 as simply being "subject to the electric reliability organization's tariff on file with the commission". REAP does not believe further definition of those obligations is necessary. What is necessary is a definition of "greatest value, consistent with the public interest",[21] which is *not* explicitly defined in SB 123.

Since the legislation already defines what the obligations of a load-serving entity are (to follow the ERO tariff), it makes far more sense to REAP that the Commission focus on defining what is the "greatest value, consistent with the public interest". The load-serving entities obligation to serve is a subset of that public interest. This understanding is consistent with section 780 (d) of the statute, which specifically requires the Commission to "adopt regulations… "determining cost-effectiveness and greatest value".

Section 780 (a) of the statute states:

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[20] AS 42.05.780 (a)

[21] Ibid.

> An integrated resource plan must include options to meet customers' *collective needs* in a manner that provides the *greatest value, consistent with the public interest*, *regardless of the location or ownership* of new facilities or conservation activities (emphasis added).[22]

REAP will discuss below how it believes "greatest value, consistent with the public interest" and cost effectiveness should be defined. First, REAP would submit that the language in Section 780 (a) contemplates that the IRP look at the needs of the *region first*, before the needs of the load-serving entities. This is clear from the language "collective needs" and "regardless of location or ownership". Those legislative statements are directing that the ERO come up with a plan that focuses on the region. It is implied that <u>all customers</u> in each of the respective load-serving entities' service areas will still benefit, but they will do so through collective action, not localized plans. REAP believes this language is also important to understanding the questions about how to move from plan to project, as raised in Questions #11 and #12 above.

Definition of "greatest value, consistent with the public interest" and "cost effectiveness"

REAP believes that "greatest value, consistent with the public interest" includes "cost effectiveness", but <u>cost effectiveness is only one element</u> of "greatest value." As noted above, the legislature, in section 780 (d) of the statute, specifically directed the Commission to:

> …adopt regulations governing the filing of a plan under this section, including the content of a plan, time for filing a plan, criteria for determining cost-effectiveness and greatest value, and other criteria as determined by the commission.

While criteria for determining cost effectiveness and greatest value are lumped together in this section of the statute, the history of SB 123 demonstrates that the legislature did not want the integrated resource planning process to be a simple cost-benefit analysis. If it did, the words "greatest value" would not appear in the statute.

REAP suggests to the Commission that it draft regulations that require the ERO to determine "greatest value, consistent with the public interest" by addressing and weighting all of the following four value criteria, and their subparts:

1) Cost effectiveness (economic value). Cost effectiveness must be determined by considering:
    a. Life cycle economics
        i. Capital expenditures
        ii. O&M (including transmission tariffs)
        iii. Estimated life cycle fuel costs

[22] Ibid.

1. Fuel storage costs
2. Price escalation assumptions

iv. Decommissioning costs
v. *Estimated* costs (public investment) versus *contracted* costs (private investment)
vi. Other hard costs (may include future carbon pricing)

b. Carbon risk (including CO_2 and CH_4)
c. Fuel risk (including availability, government subsidies and regulation risk)
d. Economies of scale (regional projects that meet collective needs regardless of location or ownership)
e. Project cost risk (public versus private investment)
f. Project operations risk (public versus private investment)
g. Extent of utilization of asset (includes existence of power purchase and dispatch agreements)
h. Ability to reduce peak loads (demand-side management, energy storage)
i. Line loss (distance from load, DERs, demand management)
j. Transmission upgrade costs
k. Other values, including ancillary services

2) Environmental Value
   a. Reduction in non-greenhouse gas pollutants including mercury, NOx, SOx and CO
   b. Fuel storage and fuel spill risk
   c. Carbon emissions
3) Community Value
   a. Preferences required in local, state and national legislation
   b. Customer support (indicated through demand discovery)
4) Reliability value
   a. Regional energy security
   b. Portfolio diversity
   c. Fuel availability
      i. Upstream fuel production risks

REAP believes the regulations should require the ERO to explain its analysis of these four value criteria and their subparts and how the ERO weighted each of the four values to determine the greatest value, consistent with the public interest. The Commission should establish a standard of review for determining whether the ERO did so properly.

15) Should regulations specify the content or process by which the phrase "full range of cost-effective means" is defined? If not, then why not? If so, then how so?

REAP believes the ERO should have to justify/demonstrate what options it did look at, and why it did not consider others. A list of possible options beyond what is included in the statute could provide guidance to the ERO. Those options could include a competitive procurement process to determine actual, not estimated, lowest cost of asset acquisition.

Options could also include an "all-requirements" RFP which would allow non-utility actors to propose providing resources at prices the non-utility can deliver upon.

Since demand-side management options are typically the most "cost-effective means for load-serving entities to meet the service requirements of all customers",[23] REAP believes it is especially important that the IRP consider how load-serving entities are presenting options to their customers to incentivize and fairly compensate flexible loads, at the customers' discretion, for the value of smoothing aggregate network capacity requirements in order to minimize the need for new network investments and to optimize the value of the network assets already in the ground.

REAP believes the language in Option #2 that "an ERO must justify how the IRP utilizes the full range of cost-effective means" is important, and could also appear in regulation to provide guidance.

16) What should the criteria for determining whether an IRP should be approved or returned for modification be?

REAP supports Option #4 from the October 21-22 Technical Conference as the most comprehensive of the choices. As REAP notes in proposed definitions of greatest value consistent with the public interest and cost effectiveness in Question #14, there are many risks associated with choices that might be made, and Option #4 does the best job of attempting to consider those risks. As REAP noted above in Question #10, it believes the IRP "process", including how the ERO engages the public in planning, should also be one of the criteria determining whether an IRP should be approved or returned for modification. The language in Option #2 that states "the IRP will 1) include robust public participation founded on timely and transparent public communication" should be added to Option #4.

REAP does believe that the Commission must be able to review the ERO's attempt in the IRP to address the "greatest value, consistent with the public interest". The Commission should establish a standard for such a review. This notion is contained in Option #3 and could also be included in Option #4.

To address the importance of DSM measures, the Commission could also add the following bullet to Option #4:

- Involve and properly reward customers who are able and willing to respond to conditions of surplus and scarcity in both supply-side resources and network capacity to minimize the cost of the system to all consumers,

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[23] Ibid.

including programs for cost-effective deployment of the necessary technology and consumer education.

Other criteria that could be used by the Commission include whether every item included in Question #1 has been addressed.[24]

Finally, the Commission should inquire about how the ERO modeled the various scenarios and sensitivity analyses in the IRP.

17) How should existing network limitations be incorporated into the relative obligations

imposed on these utilities by the formation of a limited ERO?

REAP supports Option #1 from the October 21-22 Technical Conference: *Regulations require that an ERO consider any network limitations in the development of the IRP and provide a discussion of such limitations in its IRP filing.*

Since the ERO will develop standards for transmission cost recovery and reliability standards, it is in a position to understand the relative cost burdens that may be imposed on particular load-serving entities under different portfolio options explored in an IRP. The ERO should be required to provide a discussion of how it treated network limitations.

[24] The Arizona Corporation Commission (ACC) considers the following factors when reviewing a load-serving entity's resource plan:

a. The total cost of electric energy services;
b. The degree to which the factors that affect demand, including demand management, have been taken into account;
c. The degree to which supply alternatives, such as self-generation, have been taken into account;
d. Uncertainty in demand and supply analyses, forecasts, and plans, and whether plans are sufficiently flexible to enable the load-serving, entity to respond to unforeseen changes in supply and demand factors;
e. The reliability of power supplies including fuel diversity and non-cost considerations;
f. The reliability of the transmission grid;
g. The degree to which the load-serving entity considered all relevant resources, risks and uncertainties;
h. The degree to which the load-serving entity's plan for future resources is in the best interest of its customers;
i. The best combination of expected costs and associated risks for the load-serving entity and its customers;
j. The degree to which the load-serving entity's resource plan allows for coordinated efforts with other load-serving entities.

Arizona Corporation Commission. Decision No. 71722. Docket No. RE-00000A-09-0249. Section R14-2-704. June 3, 2010 https://images.edocket.azcc.gov/docketpdf/0000112475.pdf

Large Project Preapproval

1) If a project is submitted for pre-approval outside of the IRP process, what criteria should be used to determine that the facility is necessary to the interconnected electric energy transmission network with which it would be interconnected?

REAP finds it difficult to foresee situations where new large generation or transmission projects must come to the Commission for pre-approval outside of the IRP process, particularly if IRPs are updated every three years, and only specific projects are included in preferred portfolios and/or action plans. As several utility representatives stated at the October 21-22 Technical Conference, large generation projects typically take at least five years' worth of lead time to develop. Hydro projects take even more time.

However, if there does arise a situation where a project proponent comes forward between IRPs, REAP believes that such a project should be required to conduct an analysis that is substantively similar to the analysis required in the IRP. A thorough review is important in this context. Acquisition is subject to prudence, and used and useful determination. Preapproval should not be an end-run around the IRP process. **Option #1 comes closest** to that type of analysis. However, REAP would add requirements that:

1) The project proponent demonstrate that the proposed project is more cost-effective on a system level than alternative means of delivering the same services and;
2) The project proponent demonstrate why the project in question was not considered in the most recent IRP and;
3) The ERO supports the project.

REAP would not consider emergency replacement of transmission lines damaged in a fire as a "new" project requiring approval. However, REAP would urge that before a line is replaced that the ERO compare the costs and benefits of simply replacing the line, versus upgrading the line.

2) What criteria should be used to determine that a facility meets the needs of a load-serving entity in a cost-effective manner?

REAP believes that the same criteria used in an IRP process to determine cost-effectiveness outlined above in Question #14 should be used to determine whether a facility meets the needs of a load-serving entity in a cost-effective manner. REAP believes **Option #2 comes closest** to that requirement. All the risks associated with new projects, including fuel price and construction risk should be considered.

Again, it is very hard for REAP to imagine a situation where a need comes so quickly out of the blue that meeting that need cannot done within the IRP process.

3) Should regulations address criteria for approval or disapproval when, outside of an IRP process, an LSE seeks project preapproval for a large energy facility that has material capacity or capabilities in excess of its own needs?

REAP believes it is even more unlikely that a large project in excess of one load-serving entity's own needs would surface so quickly that it would not have been part of an IRP process. As utility representatives stated during the technical conference, large projects must typically be on the drawing board at least five years before they are needed in order to be completed on time.

This question is related to issues REAP brought up in Question #11 above, including cost recovery for generation projects. REAP believes that the answer to this question should be consistent with how those issues are resolved for the IRP process.

REAP believes that if the RCA is going to consider pre-approval for a project outside of an IRP process, the criteria should be stricter than either Option #1 or Option #2.

4) How should the terms "refurbishment" or "capitalized maintenance" be defined?

REAP believes that "refurbishment" and "capitalized maintenance" should have a common sense meanings, which is probably how the legislature understood them. Any significant increase in generation capacity can and should have been anticipated and therefore should be part of an IRP process. The ERO is being established to determine what the impacts are to the system as a whole.

A point was made at the Technical Conference that a utility will "always" want to extend the life of an asset. REAP does not agree that is always the case. If a facility is already well past its expected useful life, it may make more sense for a number of reasons to consider de-commissioning the facility rather than trying to keep it limping along. Some type of objective analysis should be required whenever "refurbishment" or "capitalized maintenance" is being considered.

5) Should regulations seek to define or provide criteria for addressing when a facility "substantially serves the needs of a load serving entity"?

REAP agrees that the ERO regulations could provide the guidance described in Option #1, but REAP also believes that same guidance for how benefits of an asset are shared and allocated should be developed for the IRP process. Therefore, the same criteria the

ERO develops to determine when a facility "substantially serves the needs of a load serving entity" should be used both within and outside of the IRP process.

6) How should regulations address projects undertaken before integrated resource plan approval that do not require pre-approval?

REAP supports Option #4 from the October 21-22 Technical Conference. *Regulations provide that approval is not required if certain expenditure and project planning thresholds have been met (e.g. Front End Engineering and Design is complete) prior to SB123's effective date.*

REAP does not want to see a rush of projects that are not coordinated on a regional basis before the ERO's first IRP is completed. REAP recognizes the investment that HEA made in its battery energy storage system before SB 123 became law, and believes that Option #4 would allow that project to go forward without pre-approval.

7) How should the Commission act to maintain jurisdiction over local planning?

REAP supports Option #2 from the October 21-22 Technical Conference. *Regulations should permit the Commission to address and approve or disapprove the geographical location of a generation or transmission facility if local planning decisions result in large and otherwise unnecessary increases in project costs.*

This is consistent with REAP's belief that an IRP should consider local legislation.

REAP thanks the Commissioners and staff for all their hard work and appreciates the opportunity to provide input in R-20-002.

Respectfully,

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