

## OPEN MEETING

## MEMORANDUM

TO: THE COMMISSION

FROM: Utilities Division

DATE: July 16, 2020

RE: IN THE MATTER OF POSSIBLE MODIFICATIONS TO THE ARIZONA CORPORATION COMMISSION'S ENERGY RULES (DOCKET NO. RU-00000A-18-0284)

## INTRODUCTION

Enclosed are the Commission Staff's memorandum and proposed order in the matter of Possible Modifications to the Arizona Corporation Commission's Energy Rules (Docket No. RU-00000A-18-0284). This is only a Staff recommendation to the Commission; it has not yet become an order of the Commission. The Commission can decide to accept, amend or reject Staff's proposed order.

You may file comments to the recommendation(s) of the proposed order by filing an original and thirteen (13) copies of the comments with the Commission's Docket Control Center at 1200 West Washington Street, Phoenix, Arizona 85007 by 4:00 p.m. on or before **July 27, 2020**.

This matter may be scheduled for Commission deliberation at a future Open Meeting. The following proposed dates contained in Staff's proposed Memorandum are contingent on a Commission Decision issued on or before July 30, 2020, and are subject to change depending on when this item is heard at a Commission Open Meeting and a Commission Decision is issued.

If you have any questions about this matter, please contact our Staff, Patrick LaMere at (602) 542-4382, Zachary Branum at (602) 542-0755, or Elijah Abinah, Director, at (602) 542-6935.

## BACKGROUND

On August 14, 2018, the Arizona Corporation Commission ("Commission") directed the Utilities Division Staff ("Staff") to initiate a rulemaking docket to evaluate the proposed Arizona energy modernization<sup>1</sup>. Accordingly, this docket was opened on August 17, 2018.

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<sup>1</sup> See. Correspondence by Commissioner Tobin filed on July 5, 2018, in Docket No. R-00000Q-16-0289.

On November 30, 2018, Staff provided a memorandum to the Commissioners proposing a timeline for workshops to gather stakeholder input on the redesign of the Commission's Energy Rules<sup>2</sup>.

### *Resource Planning and Procurement Rules*

The Commission adopted Resource Planning and Procurement Rules<sup>3</sup> in 1989 for utilities defined as load serving entities (“LSE”) to meet the electric needs of their customers by choosing the best mix of resources, with input from stakeholders in a transparent process. In Commission Decision No. 71722 (June 3, 2010), the Commission amended the original Resource Planning and Procurement Rules to include consideration of a diverse portfolio of purchased power, utility-owned generation, renewables, demand-side management, and distributed generation.

The Commission’s Resource Planning and Procurement Rules outline a process for each LSE to file its integrated resource plan (“IRP”). Each LSE’s proposed IRP assesses how it will meet forecasted annual peak and energy demand through a balance of supply-side and demand-side resources over a specific time period.

### *Renewable Energy Standard and Tariff Rules*

In Commission Decision No. 69127 (November 14, 2006), the Commission adopted new Renewable Energy Standard and Tariff (“REST”) Rules<sup>4</sup> which required affected utilities to satisfy an annual renewable energy requirement. Commission Decision No. 74882 (December 31, 2014) amended the REST Rules in order to clarify and update how the Commission deals with renewable energy compliance.

In the REST Rules,<sup>5</sup> affected utilities are required to satisfy an annual renewable energy requirement up to 15 percent by 2024. Commissioners and stakeholders have expressed interest to increase the annual renewable energy requirement percentage.

### *Electric Energy Efficiency Standards Rules*

In Commission Decision No. 71819 (August 10, 2010), the Commission adopted new Electric Energy Efficiency Standards Rules (“EEE Rules”)<sup>6</sup> which required affected utilities to achieve energy savings through cost-effective energy efficiency programs, in order to ensure reliable electric service at reasonable rates and costs.

The EEE Rules require an affected utility to achieve cumulative annual energy savings, measures in kWh, equivalent to a percentage of an affected utility’s retail electric energy sales for

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<sup>2</sup> Staff’s memorandum was also made available to those attending the Staff hosted Retail Electric Competition Workshop held on December 3, 2018, at the Commission’s Phoenix Office.

<sup>3</sup> See Arizona Administrative Code (“A.A.C.”) R14-2-701 *et seq.*

<sup>4</sup> A.A.C. R14-2-1801 *et seq.*

<sup>5</sup> See A.A.C. R14-2-1804(B)

<sup>6</sup> A.A.C. R14-2-2401 *et seq.*

a specific calendar year. For calendar year 2019, an affected utility's retail electric sales must equate to at least 22 percent.

### *Gas Energy Efficiency Standards Rules*

In Commission Decision No. 72042 (December 10, 2010), the Commission adopted new Gas Energy Efficiency Standards Rules ("Gas EE Rules")<sup>7</sup> which required affected utilities to achieve therm or therm equivalent savings through Demand-side management and renewable energy resource technology programs in order to ensure reliable gas service at reasonable rates and costs through cost-effective energy efficiency programs.

The Gas EE Standards Rules require an affected utility to achieve cumulative annual energy savings each year, beginning in 2011, and equivalent to at least 6 percent of the affected utility's retail sales for calendar year 2019.

### *Net Metering*

In Decision No. 75859 (January 3, 2017) the Commission ordered Staff to file potential modifications to the current Net Metering Rules<sup>8</sup> to comport with changes in circumstances since their adoption. Accordingly, on August 18, 2017, Staff opened a new docket for the Commission's review and modification of the current Net Metering Rules to comport with changes in circumstances since their adoption.

### *Environmental Portfolio Standards*

In Decision No. 63364 (February 8, 2001), the Commission adopted the Environmental Portfolio Standard,<sup>9</sup> and on March 29, 2001, the Commission issued Decision No. 63486, which modified the Environmental Portfolio Standard.

### *Energy Rules*

On August 22, 2016, Chairman Little opened a docket for the Review, Modernization and Expansion of the Arizona Renewable Energy Standard and Tariff Rules and Associated Rules.<sup>10</sup> Written comments were received from interested parties from November 2016 through the opening of this docket.

Stakeholder Meetings were hosted by Staff on December 10, 2018; February 25, 2019; March 14, 2019; and March 26, 2019 to discuss various topics related to the Energy Rules.

On April 25, 2019, Staff filed its initial draft of proposed rules which were discussed at length at the Commission's April 29, 2019, stakeholder meeting and workshop. Staff requested interested parties to docket written comments.

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<sup>7</sup> A.A.C. R14-2-2501 *et seq.*

<sup>8</sup> A.A.C. R14-2-2301 *et seq.*

<sup>9</sup> A.A.C. R14-2-1618

<sup>10</sup> See Docket No. R-00000Q-16-0289.

On July 2, 2019, and February 18, 2020, Staff filed a second and third draft of the proposed Rules, respectively, and again requested interested parties to docket written comments.

Subsequent stakeholder meetings and workshops were hosted by Staff to discuss the Energy Rules on July 30 and 31, 2019; August 7, 2019; September 19, 2019; and March 10 and 11, 2020.

Written comments and participants in the workshops included representatives from utilities, government agencies, energy efficiency and environmental advocacy groups, utility investors, large industrial consumers, advocates for renewable resources, competitive power providers, advocates for distributed generation, product suppliers, research entities, and others.

As a result of Commissioner correspondence, written comments, and workshops, and in recognition of current National trends and developments in technology, Staff believes modification to the Commission's Resource and Procurement Rules, REST Rules, EEE Rules, and Gas EE Rules is necessary. Staff believes (i) repealing the Commission's Resource and Procurement Rules, REST Rules, EEE Rules, Gas EE Rules, and EPS Rules; (ii) Modifying the Net Metering Rules; and (iii) adopting Staff's proposed Energy Rules, proposed Article 27 of Title 14, Chapter 2, of the A.A.C. is necessary and in the public interest.

Attachment 1 details the Transcript from the March 11, 2020 Staff Workshop where votes were taken. Attachment 2 is a Summary of Commissioner correspondence filed in the Energy Rules Docket

Appendix A, B, and C are attached to Staff's Proposed Order and include: A) Staff proposed draft Energy Rules, R14-2-2701 *et seq.*; B) Staff's proposed modifications to the Commission's Net Metering Rules; and C) Strikethrough of the Commission's existing Resource and Procurement Rules, REST Rules, EEE Rules, Gas EE Rules, and EPS Rules.

## **STAFF RECOMMENDATION**

Staff has recommended that the Commission direct Staff to file, by July 31, 2020, with the office of the Secretary of State, for publication in the Arizona Administrative Register no later than August 21, 2020, (1) a Notice of Rulemaking Docket Opening and (2) a Notice of proposed Rulemaking.

Based on consultation with the Hearing Division, Staff has further recommended that the Commission direct the Hearing Division to hold oral proceedings to receive public comment on the Notice of Proposed Rulemaking on September 21, 2020, at 10:00 a.m. or as soon as practicable thereafter, in Hearing Room No. 1 at the Commission's offices in Phoenix, Arizona, and on September 24, 2020, at 10:00 a.m. or as soon as practicable thereafter, in Room 222 at the Commission's offices in Tucson, Arizona.



Staff has further recommended that interested parties be requested to provide comments concerning the Notice of proposed Rulemaking by filing written comments with the Commission's Docket Control by September 21, 2020; be requested to provide comments in response to other interested parties' comments by filing written comments with the Commission's Docket Control by September 28, 2020; and be permitted to provide oral comments at the proceedings to be held on September 21 and 24, 2020.

Staff has further recommended that the Commission establish additional procedural deadlines and requirements as may be necessary consistent with the Administrative Procedures Act and prior Commission rulemaking procedures.

A handwritten signature in blue ink, appearing to read 'Elijah O. Abinah', with a stylized, cursive script.

Elijah O. Abinah  
Director  
Utilities Division

EOA:PCL:yw\MAS

ORIGINATOR: Patrick LaMere

**Energy Rules March 11 and 12 Workshop: "Votes"**

*All votes taken in this Workshop were to be taken as directive to Staff for the draft rules and not as policy issues.*

On March 10 and 11, 2020, Staff hosted a Workshop to discuss the Energy Rules.

The video feed to the workshop is here: [https://azcc.granicus.com/player/clip/3834?view\\_id=3](https://azcc.granicus.com/player/clip/3834?view_id=3)

Following all the presentations, Chairman Burns requested a vote of the Commission on specific policy issues, starting at timestamp - 5:52:53.

**1) Energy Efficiency Standard be set to 35% by 2030 (2 Aye; 3 Nay)**

- Commissioner Marques Peterson: **Nay** - Not comfortable voting on any of these measures without further research.
- Commissioner Olson: **Nay** - Energy Efficiency is an extraordinary way to save rate payers money. EE is the least cost approach of meeting energy needs of the customer. The best approach is an all source RFP that allows all resources to compete.
- Commissioner Kennedy: **Aye** - Appreciates motion and think it takes the stakeholders into consideration.
- Commissioner Dunn: **Nay** - This vote has nothing to do with the upcoming election. There is need for more information especially from the Utilities. Commissioner Dunn showed concern that the information will come in too late for Staff to be able to put the Rules together. Does not want to delay and does not want to force a vote from Commissioners that do not feel ready to make a vote. Wants to meet in the middle with amendments. Proposing that Staff moves forward with revising proposed rules based on comments from workshop and with that information Commissioners can propose amendments before specific rule provisions. Staff's approach is too vague in EE, does not like leaving specifics to utilities proposed plans to implement. Wants concrete guidance from staff on EE programs: How should these plans be structured? What are the principles that should guide the development of EE programs? When do we want Utilities elected EE measure over purchasing generation? EE exists to mediated cost and should lead to savings for rate payers. EE applied to mediated peak. Commissioner Dunn would like to target low income areas with EE programs. Staff needs to rethink EE.
- Chairman Burns: **Aye**

**2) A Clean Energy Standard of 100% by 2050 (3 Aye; 1 Nay; 1 Abstain)**

- Commissioner Marques Peterson: **Abstains** - Votes are premature and are not data driven.
- Commissioner Olson: **Nay** - All projects should compete in a fair and just RFP and the best project should win. Have a guarantee of the most cost-effective manner. There is a great example of competitive energy in Texas where a company offers 100% Renewable Energy because of the market it is a choice. Does not want utilities to surcharge and raise rates to customers. Require all source RFP for energy resources. This is the best way to meet customer demands and provide lowest cost.
- Commissioner Kennedy: **Aye** - This is a directive to staff. Commissioners will later come with amendments the draft.

- Commissioner Dunn: **Aye** - 100% is possible and clean energy is critical. Wants Staff's opinion on the Clean peak proposal. Wants 100% clean by 2050 and clarification. Interim goals that gives utilities direct to address to Commission to achieve goal and should be mandate.
- Chairman Burns: **Aye**

#### Closing Remarks:

##### Chairman Burns:

- 50% Renewable by 2030
- DG 10% by 2030
- Staff look at Sunrun comments and Stakeholder comments on definition of DG
- Staff in IRP rules add time frames
- Cost effective analysis: cost of externalities and life cycle costs. Not just initial capital costs.
- Wants staff to review New Mexico and Colorado and ASU; Savings on closing coal plants and using renewables and sum of money programs to benefit the affected communities.

##### Commissioner Dunn:

- Wants to move away from surcharges and instead recover costs in rate cases.
- EE plan as companion to IRP plans, and meaning
- IRP every 3 years but a 15-year scope
- Commission must review and improve the EIP and IRP. Scope review to guide utility in reports
- Clean energy standard 100% must be a mandate
- Co. Ops. have concerns with rules and wants to hear from them

##### Commissioner Kennedy:

- 50% Renewable Energy by 2030
- 100% clean energy standard by 2050
- 10% from rooftop solar and wind. Encourages DR and microgrids
- 25% RE from coal impacted communities. Just transition. Reinvest in coal communities
- 35% EE by 2030. Knows its least cost effective
- Infrastructure for EV in requirements
- Tracking water usage from generation sources in standard
- Commission must set standards not goal
- Strengthen EIP and IRP process
- Staff take stake holder recommendations in proposed rules
- DG standard carve out of 10% renewable retail source DG incentives for storage and microgrids
- Demand response's standard 10% EERS from Demand Response by 2030
- Set standard of energy resource in water intensity
- Taskforce to support renewable energy development and coal impacted communities in tribal lands

Commissioner Olson:

- Best approach is free marketplace supports any proposal with the condition that utilities are using least cost method. Ideas are not mutually exclusive. All energy provider should compete and require utilities support in least cost and avoids raised rates to customers.

Commissioner Marques Peterson:

- Will make positions clear after further information is obtained and will a write letter that address all issues.



**Energy Rules: Summary of Commissioner Proposals in Docket No. RU-00000A-18-0284****Chairman Burns:** April 1, 2019; June 7, 2019; October 15, 2019 and March 25, 2020

- A New IRP Process – the All-Source RFP (“ASRFP”)
- Clean Energy Standard of 100% by 2050
- An EE Standard of 35% by 2030
- A Renewable Energy Standard of 50% by 2030
- A DG standard of 10% by 2030 (of the total 50% RES) – using non-utility owned DG.
- Section regarding Securitization and Transition from closure of fossil fuel plants
- Cost Recovery in the context of a rate case

**Commissioner Kennedy:** February 8, 2019; April 8, 2019; and January 8, 2020

- Increasing the REST to 50% by 2028
- A 100% Carbon Emissions Free Standard by 2045 (would support 2050)
- Encouraging the development of Microgrids
- Encouraging the development of distributed solar with energy storage
- Encouraging the development of battery storage
- Just Transition strategy for tribal communities transitioning from coal – implementing more renewables and energy efficiency.
- Up to 50% incentive for installation of new residential battery storage
- Up to 20% incentive for installation of new rooftop solar
- A DG Carveout of 10%
- A 25% Carveout of utility-scale renewable energy resources to be purchased from coal-impacted communities by 2028
- Tribal Lands Task Force Creation – to assure Just transition
- Securitization and Energy Transition Efforts from Coal Plants before their retirement date(s)
- Encouraging non-wires alternatives such as demand response
- Investment in Energy Efficiency
- PBIs for Microgrid development and for energy storage systems paired with renewable energy generation facilities
- An EE Standard of 35% by 2030 w/ a 10% Demand Response carveout
- An EV goal of 500,000 vehicles by 2035 w/ managed charging for Class A utilities.
- Encouraging the use of water efficient energy resources – for example, each utility would monitor, report and benchmark the water intensity and water source of each generating asset.
- Strengthening the EIP and IRP sections
- Setting an EV Infrastructure goal
- A third-party administrator for EE and DSM programs

**Commissioner Dunn:** November 20, 2018 and April 26, 2019

- A Clean Energy Standard of 85% by 2050 w/ benchmarks:
  - 25% by 2025
  - 35% by 2030
  - 45% by 2035

- 58% by 2040
- 70% by 2054
- 85% by 2050
- A Renewable Energy Standard of 35% by 2030 satisfied with RECs w/ benchmarks:
  - 23% by 2024
  - 31% by 2028
- Adding storage as an eligible renewable energy resource
- Only new DG Carveout of 4% of the total 35% RES.
- Extend the use of the Renewable Energy Storage Extra Credit Multiplier
- Extend the use of a Distributed Solar Electric Generator and Solar Incentive Program Extra Credit Multiplier
- Incorporate Biomass policy Statement (Decision No. 77045)
- Include a Bioenergy Multiplier
- An Energy Efficiency Standard that captures demand response and load management programs under the new heading of peak reduction programs.
- A Storage Extra Savings Multiplier – targeting peak reductions
- Incentives for EV Charging Infrastructure
- An Energy Efficiency Standard of 35% by 2030 w/ benchmarks:
  - 26% by 2024
  - 31% by 2028
- Seasonal EE Valuation
- Incorporate EV Policy Statement (Decision No. 77044)
- EV Infrastructure Multiplier (before 2025)
- Low-Income EV Energy Savings Multiplier
- For Coops:
  - A Clean Energy Goal of 30% by 2040
  - A compliance update in their respective plans every 4 years

**Commissioner Olson:** February 21, 2019; April 3, 2019; August 15, 2019; and March 23, 2020

- Prioritize Retail Competition
- Replace the REST Standard w/ a requirement that utilities invest in the most cost-effective mix of energy generation methods
- Capping the funds that utilities can spend in excess of the cost of conventional energy generation and delivery.
- Supports an All-Source RFP process
- Supports the use of an independent monitor for the ASRFP

**Commissioner Marquez-Peterson:** March 12, 2020; and March 20, 2020

- In the short-term, Staff prepare a Policy Statement for clean energy to be voted on by the Commission.
- A Clean Energy Standard of 100% by 2050
- A reinvigorated IRP process w/ the Energy Implementation Plans
- Support for the All-Source RFP process

- Data-driven decision regarding renewable, EE, DG+ Storage, and EV Development;
- Use of cost-effective demand side management programs and energy efficiency resources as a least-cost alternative to balancing the interests of sustainability and affordability in utility rates; and

**General Consensus on Policy in Proposals:**

1. A Clean Energy Standard of 100% by 2050
2. The All-Source RFP process
3. An EE Standard of 35% by 2030
4. Some percentage of a Renewable Energy Standard
5. A 10% DG Standard (of a Renewable Energy Standard)
6. Just Transition and Securitization Consideration – for early closure of Coal Plants

1 **BEFORE THE ARIZONA CORPORATION COMMISSION**

2 ROBERT "BOB" BURNS  
Chairman

3 BOYD DUNN  
Commissioner

4 SANDRA D. KENNEDY  
Commissioner

5 JUSTIN OLSON  
Commissioner

6 LEA MÁRQUEZ PETERSON  
Commissioner

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8 IN THE MATTER OF POSSIBLE  
9 MODIFICATIONS TO THE ARIZONA  
10 CORPORATION COMMISSION'S ENERGY  
11 RULES.  
12

DOCKET NO. RU-00000A-18-0284

DECISION NO. \_\_\_\_\_

ORDER

13 Open Meeting  
14 July 30, 2020  
Phoenix, Arizona

15 BY THE COMMISSION:

16 FINDINGS OF FACT

17 1. On August 14, 2018, the Arizona Corporation Commission ("Commission") directed  
18 the Utilities Division Staff ("Staff") to initiate a rulemaking docket to evaluate the proposed Arizona  
19 energy modernization.<sup>1</sup> Accordingly, this docket was opened on August 17, 2018.

20 2. On November 30, 2018, Staff provided a memorandum to the Commissioners  
21 proposing a timeline for workshops to gather stakeholder input on the redesign of the Commission's  
22 Energy Rules.<sup>2</sup>

23 *Resource Planning and Procurement Rules*

24 3. The Commission adopted Resource Planning and Procurement Rules<sup>3</sup> in 1989 for  
25 utilities defined as load serving entities ("LSE") to meet the electric needs of their customers by  
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7 meet forecasted annual peak and energy demand through a balance of supply-side and demand-side  
8 resources over a specific time period.

9 *Renewable Energy Standard and Tariff Rules*

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11 new Renewable Energy Standard and Tariff ("REST") Rules<sup>4</sup> which required affected utilities to  
12 satisfy an annual renewable energy requirement. Commission Decision No. 74882 (December 31,  
13 2014) amended the REST Rules in order to clarify and update how the Commission deals with  
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15 6. In the REST Rules,<sup>5</sup> affected utilities are required to satisfy an annual renewable  
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22 electric service at reasonable rates and costs.

23 8. The EEE Rules require an affected utility to achieve cumulative annual energy  
24 savings, measures in kWh, equivalent to a percentage of an affected utility's retail electric energy  
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27 4 A.A.C. R14-2-1801 *et seq.*

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1 sales for a specific calendar year. For calendar year 2019, an affected utility's retail electric sales  
2 must equate to at least 22%.

3 *Gas Energy Efficiency Standards Rules*

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15 circumstances since their adoption. Accordingly, on August 18, 2017, Staff opened a new docket for  
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21 63486, which modified the Environmental Portfolio Standard.

22 *Energy Rules*

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<sup>10</sup> See Docket No. R-00000Q-16-0289.

1 Written comments were received from interested parties from November 2016 through the opening  
2 of this docket.

3 14. Stakeholder Meetings were hosted by Staff on December 10, 2018; February 25,  
4 2019; March 14, 2019; and March 26, 2019 to discuss various topics related to the Energy Rules.

5 15. On April 25, 2019, Staff filed its initial draft of proposed rules which were discussed  
6 at length at the Commission's April 29, 2019, stakeholder meeting and workshop. Staff requested  
7 interested parties to docket written comments.

8 16. On July 2, 2019, and February 18, 2020, Staff filed a second and third draft of the  
9 proposed rules, respectively, and again requested interested parties to docket written comments.

10 17. Subsequent stakeholder meetings and workshops were hosted by Staff to discuss the  
11 Energy Rules on July 30 and 31, 2019; August 7, 2019; September 19, 2019; and March 10 and 11,  
12 2020.

13 18. Written comments and participants in the workshops included representatives from  
14 utilities, government agencies, energy efficiency and environmental advocacy groups, utility  
15 investors, large industrial consumers, advocates for renewable resources, competitive power  
16 providers, advocates for distributed generation, product suppliers, research entities, and others.

17 19. As a result of Commissioner correspondence, written comments, and workshops, and  
18 in recognition of current National trends and developments in technology, Staff believes  
19 modification to the Commission's Resource and Procurement Rules, REST Rules, EEE Rules, and  
20 Gas EE Rules is necessary. Staff believes (i) repealing the Commission's Resource and Procurement  
21 Rules, REST Rules, EEE Rules, Gas EE Rules, and EPS Rules; (ii) Modifying the Net Metering  
22 Rules; and (iii) adopting Staff's proposed Energy Rules, proposed Article 27 of Title 14, Chapter 2,  
23 of the A.A.C. is necessary and in the public interest.

24 20. Appendix A, B, and C are attached to Staff's Proposed Order and include: A) Staff  
25 proposed draft Energy Rules, R14-2-2701 et seq.; B) Staff's proposed modifications to the  
26 Commission's Net Metering Rules; and C) Strikethrough of the Commission's existing Resource  
27 and Procurement Rules, REST Rules, EEE Rules, Gas EE Rules, and EPS Rules.

28

**Staff Recommendation**

21. Staff has recommended that the Commission direct Staff to file, by July 31, 2020, with the office of the Secretary of State, for publication in the *Arizona Administrative Register* no later than August 21, 2020, (1) a Notice of Rulemaking Docket Opening and (2) a Notice of proposed Rulemaking.

22. Based on consultation with the Hearing Division, Staff has further recommended that the Commission direct the Hearing Division to hold oral proceedings to receive public comment on the Notice of Proposed Rulemaking on September 21, 2020, at 10:00 a.m. or as soon as practicable thereafter, in Hearing Room No. 1 at the Commission's offices in Phoenix, Arizona, and on September 24, 2020, at 10:00 a.m. or as soon as practicable thereafter, in Room 222 at the Commission's offices in Tucson, Arizona.

23. Staff has further recommended that interested parties be requested to provide comments concerning the Notice of proposed Rulemaking by filing written comments with the Commission's Docket Control by September 21, 2020; be requested to provide comments in response to other interested parties' comments by filing written comments with the Commission's Docket Control by September 28, 2020; and be permitted to provide oral comments at the proceedings to be held on September 21 and 24, 2020.

24. Staff has further recommended that the Commission establish additional procedural deadlines and requirements as may be necessary consistent with the Administrative Procedures Act and prior Commission rulemaking procedures.



CONCLUSIONS OF LAW

1. Pursuant to Article XV of the Arizona Constitution and A.R.S. Title 40 generally, the Commission has jurisdiction over the matters raised herein.

2. It is in the public interest to adopt Staff's recommendations.

ORDER

IT IS THEREFORE ORDERED that the Utilities Division shall prepare and file, by July 31, 2020, with the office of the Secretary of State, for publication in the Arizona Administrative Register no later than August 21, 2020, (1) a Notice of Rulemaking Docket Opening and (2) a Notice of Proposed Rulemaking that includes the text of the rules as included in Exhibit A, attached hereto and incorporated herein by reference.

IT IS FURTHER ORDERED that the Hearing Division shall hold oral proceedings to receive public comment on the Notice of Proposed Rulemaking on September 21, 2020 at 10:00 a.m. or as soon as practicable thereafter, in Hearing Room No. 1 at the Commission's offices in Phoenix, Arizona, and on September 24, 2020, at 10:00 a.m. or as soon as practicable thereafter, in Room 222 at the Commission's offices in Tucson, Arizona.

IT IS FURTHER ORDERED that the Hearing Division shall hold each oral proceeding telephonically, unless the COVID-19 pandemic control measures in place for the Commission at the time allow for in-person proceedings.

IT IS FURTHER ORDERED that if, prior to September 21, 2020, pandemic control measures in place for the Commission allow for in-person proceedings, the Hearing Division shall provide notice that the following in-person oral proceedings shall be held, through issuance of a Procedural Order in the docket for this matter and the posting of notice on the Commission's online hearing calendar:

Date	Time	Location
September 21, 2020	10:00 a.m.	Hearing Room 1 Arizona Corporation Commission 1200 West Washington Street Phoenix, AZ 85007
September 24, 2020	10:00 a.m.	Room 222 State Building 400 West Congress Street Tucson, AZ 85701

IT IS FURTHER ORDERED that any interested person may provide public comment telephonically during either oral proceeding by calling 1-888-450-5996 and using passcode 457395#, regardless of whether in-person participation is also allowed.

IT IS FURTHER ORDERED that the Utilities Division shall ensure that the Preamble for the Notice of Proposed Rulemaking includes the information regarding the oral proceedings provided in the previous four ordering paragraphs.

IT IS FURTHER ORDERED that interested persons shall be requested to provide initial comments concerning the Notice of Proposed Rulemaking by filing written comments with the Commission's Docket Control by September 21, 2020; be requested to provide comments in

1 response to other interested persons' comments by filing written comments with the Commission's  
2 Docket Control by September 28, 2020; and be permitted to provide oral comments at the  
3 proceedings to be held on September 21 and 24, 2020.

4 IT IS FURTHER ORDERED that the Utilities Division shall ensure that the Preamble to the  
5 Notice of Proposed Rulemaking conforms with the requirements of A.R.S. § 41-1001(16) and  
6 provides notice of the date, time, and location of the oral proceedings required herein.

7 IT IS FURTHER ORDERED that the Utilities Division shall ensure that the Preamble to the  
8 Notice of Proposed Rulemaking states that (1) written comments on the Notice of Proposed  
9 Rulemaking must include a reference to Docket No. RU-00000A-18-0284; (2) initial written  
10 comments should be filed with the Commission's Docket Control by September 21, 2020; (3) written  
11 comments in response to other interested persons' comments should be filed with the Commission's  
12 Docket Control by September 28, 2020; and (4) oral comments may be provided at the proceedings  
13 to be held on September 21 and 24, 2020.

14 IT IS FURTHER ORDERED that the Utilities Division shall ensure that any written  
15 comments filed with the Utilities Division rather than the Commission's Docket Control are filed  
16 with the Commission's Docket Control.

17 IT IS FURTHER ORDERED that the Utilities Division shall, by August 21, 2020, file with  
18 the Commission's Docket Control an Economic, Small Business, and Consumer Impact Statement  
19 that addresses the economic impacts of the recommended changes to the rules as included in Exhibit  
20 A and conforms to the requirements of A.R.S. § 41-1057(A)(2).

21 IT IS FURTHER ORDERED that the Utilities Division shall, on or by October 8, 2020, file  
22 with the Commission's Docket Control a document including (1) a summary of any written  
23 comments filed by interested persons between the effective date of this Order and September 28,  
24 2020, and (2) the Utilities Division's responses to those comments.

25 IT IS FURTHER ORDERED that the Utilities Division shall, by October 15, 2020, file with  
26 the Commission's Docket Control a document including (1) a summary of all written comments  
27 filed by interested persons after September 28, 2020, and all oral comments received at the oral  
28 proceedings in this matter; (2) the Utilities Division's responses to those comments; and (3) a revised

Economic, Small Business, and Consumer Impact Statement or a memorandum explaining why no revision of the prior filed Economic, Small Business, and Consumer Impact Statement is necessary.

IT IS FURTHER ORDERED that this Decision shall become effective immediately.

**BY THE ORDER OF THE ARIZONA CORPORATION COMMISSION**

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CHAIRMAN BURNS      COMMISSIONER DUNN      COMMISSIONER KENNEDY

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COMMISSIONER OLSON      COMMISSIONER MÁRQUEZ PETERSON

IN WITNESS WHEREOF, I, MATTHEW J. NEUBERT,  
Executive Director of the Arizona Corporation Commission,  
have hereunto, set my hand and caused the official seal of this  
Commission to be affixed at the Capitol, in the City of  
Phoenix, this \_\_\_\_\_ day of \_\_\_\_\_, 2020.

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MATTHEW J. NEUBERT  
EXECUTIVE DIRECTOR

DISSENT: \_\_\_\_\_

DISSENT: \_\_\_\_\_

EOA:PCL:yw/MAS

**TITLE 14. PUBLIC SERVICE CORPORATIONS; CORPORATIONS AND ASSOCIATIONS; SECURITIES REGULATION**

**CHAPTER 2. CORPORATION COMMISSION**

**FIXED UTILITIES**

**ARTICLE 27. ENERGY RULES**

Section

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R14-2-2702. Applicability

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R14-2-2716. Waivers and Exemptions

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Appendix A. Integrated Resource Plan Document Structure

## **ARTICLE 27. ENERGY RULES**

### **R14-2-2701. Definitions**

In this Article, unless otherwise specified:

1. "Acknowledgment" means a Commission determination that a Load-Serving Entity's IRP meets the reporting requirements of this Article.
2. "Action Plan" means a Load-Serving Entity's three-year schedule of resource planning actions to be taken to implement its IRP.
3. "Affiliated" means related through ownership of voting securities, through contract, or otherwise in such a manner that one entity directly or indirectly controls another, is directly or indirectly controlled by another, or is under direct or indirect common control with another entity.
4. "All-Source Request for Proposals" or "All-Source RFP" means a process wherein the Utility solicits open all-source bids from market participants to address the Utility's resource needs.
5. "Approval" means Commission authorization to take an action or implement a plan.
6. "Benchmark" means to calibrate against a known set of values or standards.
7. "Btu" means British thermal unit.
8. "Capacity" means the nameplate rating of a Generating Unit.
9. "Capacity Factor" means the ratio of power produced by a Generating Unit in a given period of time compared to the maximum amount it could generate in the same period of time without interruption.
10. "Capital costs" means the construction and installation cost of facilities, including land, land rights, structures, and equipment.
11. "Clean Energy Resource" means a source of energy conforming to R14-2-2704.
12. "Coincident Peak" means the maximum aggregate sum of system demand within a specific time period.
13. "Commission" means the Arizona Corporation Commission.
14. "Cooperative" means a Utility that is:
  - a. Not operated for profit; and
  - b. Owned and controlled by its members.



15. “Cost-Effective” means that total Incremental Benefits exceed total Incremental Costs over the life of Demand-Side Resource.
16. “Customer” means the individual or entity in whose name service is rendered to a single contiguous field, location, or facility.
17. “Customer Class” means a subset of Customers categorized according to similar characteristics, such as:
- a. Amount of energy consumed;
  - b. Amount of demand placed on the energy supply system at the system peak;
  - c. Hourly, daily, or monthly load pattern;
  - d. Primary type of activity engaged in by the Customer, such as residential, commercial, industrial, agricultural, or governmental; or
  - e. A specific geographical location.
18. “Decommission” means to safely and economically remove a Generating Unit from service.
19. “Demand Response” means modification of Customers’ energy consumption patterns, affecting the timing or quantity of Customer demand and usage, achieved through intentional actions taken by a Utility or the Customer.
20. “Demand-Side Management” or “DSM” means the beneficial reduction in the Total Cost of meeting energy service needs by reducing or shifting the time of energy usage.
21. “Demand-Side Resource” means any DSM Measure, DSM Program, Demand Response-based mechanism, Energy Efficiency-based mechanism, or Load Management-based mechanism.
22. “Derate” means to reduce a Generating Unit’s Capacity.
23. “Discount Rate” means the interest rate used to calculate the present value of a cost.
24. “Distributed Generation” means any type of electrical Generating Unit, including all inverter(s) and protective, safety, and associated equipment necessary to produce electric power, that is located on the Distribution System or any subsystem of the Distribution System, or behind the Customer meter.
25. “Distributed Renewable Storage Standard” means the percentage of an Electric Utility’s annual retail electric sales that is required to be derived from a Customer-owned or Customer-leased Renewable Energy Resource paired with an Energy Storage System.

26. “Distribution System” means the infrastructure constructed, maintained, and operated by a Utility to deliver service at the distribution level (69 kV or less) to its Customers.
27. “DSM Measure” means any material, device, technology, educational program, pricing option, practice, or facility alteration designed to result in reduced peak demand, increased Energy Efficiency, or shifting of energy consumption to off-peak periods.
28. “DSM Program” means a Utility program provided as part of a single offering to its Customers designed to implement:
- a. One or more DSM Measures;
  - b. Demand Response; or
  - c. Energy Efficiency.
29. “Electric Utility” means a public service corporation under Arizona Constitution, Article 15, § 2, providing electric service to the public in Arizona.
30. “Emergency” means an unforeseen and unforeseeable condition that:
- a. Does not arise from a Utility’s failure to engage in Good Utility Practice;
  - b. Is temporary in nature; and
  - c. Threatens Reliability or poses another significant risk to the system.
31. “End Use” means the final application of energy, for activities such as, but not limited to, heating, cooling, running an appliance or motor, an industrial process, or lighting.
32. “Energy Efficiency” means the production or delivery of an equivalent level and quality of End Use electric or Gas service using less energy, or the conservation of energy by a Customer.
33. “Energy Efficiency Report” means a Utility’s plan to implement Demand-Side Resources.
34. “Clean Energy Implementation Plan” means an Electric Utility’s plan, filed with the Commission, for meeting the goals and standards of this Article.
35. “Energy Losses” means the quantity of energy generated or purchased that is not available for sale for End Use, for resale, or for use by a Utility.
36. “Energy Storage System” means equipment capable of storing generated energy and provides a means to discharge that energy at a later time.
37. “Environmental Benefits” means any avoided costs for compliance with regulatory requirements for, and any reduced adverse impacts to the environment from mitigating or eliminating acts such as:

- a. Water use and water contamination;
  - b. Storage and disposal of solid waste;
  - c. Burning fossil fuels; and
  - d. Producing fuels and energy.
38. "Gas" means either natural gas or propane.
39. "Gas Utility" means a public service corporation under Arizona Constitution, Article 15, § 2, providing Gas services to the public in Arizona.
40. "Generating Unit" means a specific device or set of devices that converts one form of energy into another form of energy.
41. "Good Utility Practice" means any of the practices, methods, and acts engaged in or approved by a significant portion of the energy industry during the relevant time period, or any of the practices, methods, and acts that, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with Reliability, safety, efficiency, and expedition. Good Utility Practice is not intended to be limited to the optimal practice, method, or act to the exclusion of all others, but rather to include practices, methods, or acts generally accepted in the region at the relevant time.
42. "Heat Rate" means a measure of Generating Unit thermal efficiency expressed in Btu per net kWh and computed by dividing the total Btu content of fuel used for electric generation by the total kWh of energy generated.
43. "Hosting Capacity" means the amount of Distributed Generation Capacity that a Distribution System can reliably accommodate without adversely affecting voltage, protection and power quality and without the need of infrastructure upgrades.
44. "Incremental Benefits" means amounts saved by a Utility through avoiding costs for fuel, purchased power, new Capacity, transmission, distribution, and other cost items necessary to provide electric service or Gas service, as applicable, along with Environmental Benefits.
45. "Incremental Costs" means the expenses of a DSM Measure or DSM Program exceeding the expenses estimated to occur in the absence of the DSM Measure or DSM Program considering the level of energy or Gas demand, energy or Gas consumption, and associated expenses.

46. “Independent Monitor” means an individual or entity that is not Affiliated with a Utility and that is selected to oversee the conduct of a competitive procurement process.
47. “Integrated Resource Plan” or “IRP” means a Load-Serving Entity’s plan to meet forecasted annual peak and energy demand through a combination of Supply-Side and Demand-Side Resources in accordance with laws and regulations that constrain resource selection and this Article.
48. “Integration” means methods by which energy produced can be incorporated into the electric grid.
49. “Interruptible Service” means power made available under an agreement that permits curtailment or cessation of delivery by the supplier.
50. “In-Service Date” means the date a resource becomes available for use by a Utility.
51. “Kilowatt-hour” or “kWh” means the electric energy equivalent to the amount of electric energy delivered in one hour when delivery is at a constant rate of one kilowatt.
52. “Limited-Income Customer” means a Customer with below average level of household income, as defined by Utility in its Energy Efficiency Report.
53. “Load Forecast” means an estimate or projection of a Utility’s electric loads and the factors that affect those loads in order to determine, as accurately as possible, the Utility’s future demand for energy and Capacity.
54. “Load Management” means actions taken or sponsored by a Utility to reduce peak demands or improve system operating efficiency, such as:
- a. Utilizing an Energy Storage System;
  - b. Educational campaigns to encourage Customers to shift loads; or
  - c. Direct control by the Utility of Customer demands through Interruptible Service.
55. “Load-Serving Cooperative” means a Load-Serving Entity that is a Cooperative.
56. “Load-Serving Entity” means an Electric Utility that provides energy generation service and operates or owns, in whole or in part, a Generating Unit or Generating Units with aggregate Capacity of at least 50 megawatts.
57. “Maintenance” means the repair of generation, transmission, distribution, administrative, and general facilities; replacement of minor items; and installation of materials to preserve the efficiency and working condition of facilities.

58. "Mothball" means to classify a Generating Unit as unavailable for service, although it can be brought back into service.
59. "Operate" means to manage or otherwise be responsible for the production of energy by a Generating Unit, whether that Generating Unit is owned by the operator, in whole or in part, or by another entity.
60. "Planning Period" means the forecasted period of time that a Load-Serving Entity's IRP must satisfy.
61. "Preferred Resource Portfolio" means the Load-Serving Entity's combination of selected supply-side resources and Demand-Side Resources over the Planning Period that meets the electric demand in a safe, reliable, and efficient manner and takes cost, risk, and safety into consideration while resulting in a long-term reasonable cost.
62. "Probabilistic Analysis" means a systematic evaluation of the possible events affecting factors that influence costs, Reliability, or other measures of performance, taking into consideration the likelihood that the events will occur.
63. "Production Cost" means the variable operating costs and maintenance costs of producing energy through generation plus the cost of purchases of power sufficient to meet the Utility's demand.
64. "Refurbish" means to make major changes, more extensive than maintenance or repair, in the power production, transmission, or distribution characteristics of a component of the power supply system, such as by changing the fuels that can be used in a Generating Unit or changing the Capacity of a Generating Unit.
65. "Reliability" means a measure of the ability of a Load-Serving Entity's generation, transmission, or distribution system to provide power without failures, reflecting the portion of time that a system is unable to meet demand or the kilowatt-hours of demand that could not be supplied.
66. "Renewable Energy Resource" means a source of energy conforming to R14-2-2703.
67. "Request for Proposals" or "RFP" means an independent document that solicits proposals through a bidding process.
68. "Reserve Requirements" means the Capacity that a Load-Serving Entity must maintain in excess of its peak load to provide for scheduled maintenance, forced outages, unforeseen loads, Emergencies, system operating requirements, and any agreement to provide backup Capacity to another Load-Serving Entity.

69. “Resource Procurement Action” means a resource change, addition, or retirement proposed by a Utility.
70. “Sensitivity Analysis” means a systematic assessment of the degree of response of costs, Reliability, or other measures of performance to changes in assumptions about factors that influence performance.
71. “Spinning Reserve” means the Capacity a Load-Serving Entity must maintain connected to the system and ready to deliver power promptly in the event of an unexpected loss of generation source, expressed as a percentage of peak load, a percentage of the production Capacity of the largest Generating Unit, or in fixed megawatts.
72. “Staff” means individuals working for the Commission, whether as employees or through contract.
73. “Supply-Side Resource” means a resource that provides a supply of energy, Capacity, or grid services, to a Utility
74. “Total Cost” means all capital, operating, maintenance, fuel, and Decommissioning costs, plus the costs associated with mitigating any adverse environmental effects in the provision or conservation of electric energy.
75. “Utility” means an Electric Utility or Gas Utility.
76. “Western Interconnection” means the synchronously operated interconnected electrical transmission system comprising the geographic areas of the western United States, western Canada, and northern Mexico.

**R14-2-2702. Applicability**

This Article applies to each Utility that has more than half of its Customers located in Arizona.

**R14-2-2703. Renewable Energy Resources**

**A. The following are Renewable Energy Resources:**

1. A “Biogas Electric Generator,” which uses as fuel, gases produced from plant-derived organic matter, animal waste, a wastewater treatment facility using anaerobic digestion or, an oxidation process, or another gasification process that produces energy;
2. A “Biopower Electric Generator,” which uses as fuel any raw or processed plant-derived organic matter available on a renewable basis and that has zero net life-cycle carbon emissions, including: agricultural food and feed crops; agricultural crop wastes and residues; wood wastes and residues, including landscape waste, right-of-way tree trimmings, or small diameter forest thinnings that are



12" in diameter or less; dead and downed forest products; aquatic plants; animal wastes; other vegetative waste materials; non-hazardous plant matter waste material that is segregated from other waste; forest-related resources, such as harvesting and mill residue, pre-commercial thinnings, slash, and brush; miscellaneous waste, such as waste pellets, crates, and dunnage; and recycled paper fibers that are no longer suitable for recycled paper production;

3. A "Geothermal Generator," which uses heat from within the earth's surface to produce energy;

4. A "Hydropower Facility," which generates energy using:

a. A low-head, micro hydro run-of-the-river system that does not require any new damming of the flow of the stream;

b. An existing dam without requiring a new dam, diversion structures, or a change in water flow that will adversely impact fish, wildlife, or water quality;

c. A new dam without adversely impacting fish, wildlife, or water quality; or

d. Canals or other irrigation systems.

5. "Solar Energy Resources," which use sunlight or solar heat to produce energy with either photovoltaic devices or solar thermal electric devices; and

6. A "Wind Generator," which produces energy using a mechanical device that is driven by wind.

B. Upon application, or upon its own initiative, the Commission may determine by order, that an additional technology is a Renewable Energy Resource if the technology uses naturally replenishing materials or processes to produce energy and has Environmental Benefits.

#### **R14-2-2704. Clean Energy Resources**

A. The following are Clean Energy Resources:

1. A Renewable Energy Resource;

2. A Demand-Side Resource; and

3. A Nuclear Power Generator that produces energy using nuclear fusion or fission and any reactor type approved by the approved by the United States Nuclear Regulatory Commission.

B. Upon application, or upon its own initiative, the Commission may determine by order, that an additional technology is a Clean Energy Resource if the technology operates with zero net emissions beyond that of a steam.

#### **R14-2-2705. Clean Energy Implementation Plan**

- A. An Electric Utility shall, by April 1 every third year, beginning April 1, 2023, file with the Commission a Clean Energy Implementation Plan describing how the Electric Utility intends to comply with this Article.
- B. An Electric Utility's Clean Energy Implementation Plan shall be designed to achieve the following:
1. By December 31, 2035, at least 50% of its retail kWh sales shall be derived from Renewable Energy Resources, with at least 10% of its retail kWh sales derived from Distributed Renewable Storage; and
  2. By December 31, 2050, 100% of its retail kWh sales shall be derived from Clean Energy Resources.
- C. An Electric Utility shall include in its Clean Energy Implementation Plan the following information:
1. An Executive Summary of its Clean Energy Implementation Plan;
  2. A summary of actions to be taken for the next three calendar years to meet the requirements of subsection (B) including:
    - a. Projected monthly Coincident Peak demand and energy consumption, disaggregated by Customer Class; and
    - b. A schedule of each Renewable Energy Resource and Clean Energy Resource to be added; and
    - c. For each Renewable Energy Resource and Clean Energy Resource:
      - i. The technology type;
      - ii. A description of the kW and kWh to be obtained;
      - iii. Whether the resource is used to meet the Distributed Renewable Storage Standard;
      - iv. The estimated Total Cost per kWh and per year; and
      - v. A description of the method by which each resource is to be obtained, such as self-build, Customer installation, or RFP;
  3. For the previous three calendar years:
    - a. Monthly Coincident Peak demand and energy consumption, disaggregated by Customer Class;
    - b. The kWh sales from Clean Energy Resources during the Electric Utility's monthly Coincident Peak demand, disaggregated by Clean Energy Resource and Customer Class;
    - c. Total kWh obtained from Clean Energy Resources and Renewable Energy Resources, disaggregated by technology type;

- d. Total kWh obtained to meet the Distributed Renewable Storage Standard;
  - e. Total kW of generation Capacity, disaggregated by technology type;
  - f. Total Costs per kWh obtained from Clean Energy Resources and cents per kW of generation Capacity, disaggregated by technology type; and
  - g. A description of the Electric Utility's competitive procedures for choosing Clean Energy Resources including reason why those competitive procedures are fair and unbiased and have been appropriately applied;
- 4. A summary of each program developed by the Electric Utility to encourage Customer adoption of an Energy Storage System that is paired with Distributed Generation installed on the Customer's premise;
  - 5. A summary of each program developed by the Electric Utility that utilizes Customer-owned Distributed Generation to either meet the Electric Utility's resource needs or offset future resource needs;
  - 6. A summary of each program to implement electric vehicle infrastructure in the Electric Utility's service territory; and
  - 7. An Electric Utility shall, in its Clean Energy Implementation Plan, include an Energy Efficiency Report in accordance with R14-2-2710 with a description of each Demand-Side Resource used towards its Clean Energy Implementation Plan or, if no Demand-Side Resource was used, an explanation why no Demand-Side Resource was used.
- D. An Electric Utility may provide a Customer a financial incentive to have an Energy Storage System installed on the Customer's premise.
- E. In its Clean Energy Implementation Plan, an Electric Utility shall demonstrate the delivery of energy from Clean Energy Resources and Renewable Energy Resources to its Customers by providing documentation such as:
- 1. The transmission rights to deliver energy from Clean Energy Resources or Renewable Energy Resources to the Electric Utility's system, if applicable;
  - 2. A control area operator scheduling the energy from Clean Energy Resources or Renewable Energy Resources for delivery to the Electric Utility's system, if applicable; and

3. For an Energy Storage System used to meet the Distributed Renewable Storage Standard, the source of the energy that is being used to charge the Energy Storage System.

F. If an Electric Utility's Clean Energy Implementation Plan does not contain sufficient information to allow Staff to analyze the submission fully for compliance with this Article, Staff shall request additional information from the Electric Utility, which may include the data used in the Electric Utility's analyses.

**R14-2-2706. Preliminary Integrated Resource Plan**

A. A Load-Serving Entity shall, by April 1 of the year before its IRP is due, beginning April 1, 2022, file with the Commission a Preliminary IRP describing how the Load-Serving Entity intends to comply with this Article.

B. A Load-Serving Entity shall include in its Preliminary IRP:

1. A request for Commission Approval of its Preliminary IRP;
2. A summary of its Load Forecast, along with all supporting data used to develop its Load Forecast;
3. At least three alternative Load Forecasts of peak demand and energy demand, including:
  - a. A scenario of no-load growth;
  - b. A scenario of lower than expected growth; and
  - c. A scenario of higher than expected growth.
4. A summary of Supply-Side Resources and Demand-Side Resources that have the potential to meet its Load Forecast; and
5. Each portfolio of resources that will be analyzed by the Load-Serving Entity in its IRP.
6. A summary of how the Load-Serving Entity's Advisory Council has contributed to the development of its Preliminary IRP
7. A description of how the Load-Serving Entity's IRP will be developed over the following year and specifying:
  - a. Opportunities for the general public to participate; and
  - b. The Load-Serving Entity's plans for hosting at least one technical workshop, open to the general public and the Commission;
  - c. How the Load-Serving Entity's IRP Advisory Council will contribute to the development of its IRP; and

d. A schedule of dates in which the Load-Serving Entity plans to meet with its IRP Advisory Council.

C. Within 60 calendar days after a Load-Serving Entity files its Preliminary IRP, the Commission shall, in coordination with the Load-Serving Entity, host a workshop, open to the general public, to discuss at least the following aspects of Preliminary IRP:

1. The Load Forecast developed by the Load-Serving Entity;
2. Each portfolio of resources the Load-Serving Entity plans to analyze in its IRP; and
3. The modeling assumptions, outputs, and methodologies used.

**R14-2-2707. Integrated Resource Plan**

A. A Load-Serving Entity shall, by April 1 every third year, beginning April 1, 2023, file with the Commission an IRP describing how the Load-Serving Entity intends to comply with this Article and organized in accordance with Appendix A.

B. A Load-Serving Entity's IRP shall consider a Planning Period of 10 years.

C. A Load-Serving Entity's IRP shall include:

1. A Clean Energy Implementation Plan in accordance with R14-2-2705;
2. An Action Plan that includes, at a minimum:
  - a. A summary of the results of the Load-Serving Entity's RFP processes;
  - b. For the next three calendar years, the Resource Procurement Actions the Load-Serving Entity plans to undertake based on proposals received in response to its RFP processes; and
  - c. A three-year timeline that describes the Load-Serving Entity's loads and resources.
3. An executive summary that describes the Load-Serving Entity's Preferred Resource Portfolio;
4. An explanation of the Load-Serving Entity's future planning and public advisory process, which shall include:
  - a. A description of all stakeholder meetings and engagements that took place to support the development of its IRP;
  - b. A description of relevant contemporary resource planning issues that affect the Load-Serving Entity and the Western Interconnection;

- c. A description of feedback the Load-Serving Entity has received based on its previous IRP process and of current activities or plans that the Load-Serving Entity is undertaking to improve its IRP process;
- d. A description of the Load-Serving Entity's method for assessing potential resources; and
- e. A description of the key planning assumptions made by the Load-Serving Entity in the development of its IRP and sources of those assumptions.
- 5. An explanation of the Load-Serving Entity's resource needs, which shall include:
  - a. The Load-Serving Entity's Load Forecast and at a minimum, the following information:
    - i. A Planning Period forecast of system Coincident Peak load (megawatts) and energy consumption (megawatt-hours) by month and year, expressed separately for residential, commercial, industrial, and other Customer Classes; for Interruptible Service; for resale; and for energy losses;
    - ii. Disaggregation of the Load Forecast into a component in which no additional Demand-Side Resources are assumed, and a component assuming the change in load due to additional forecasted Demand-Side Resources;
    - iii. Documentation of all sources of data, analyses, methods, and assumptions used in making the Load Forecasts, including a description of how the forecasts were Benchmarked and justifications for selecting the methods and assumptions used;
    - iv. A forecast of Customer-owned Distributed Generation;
    - v. A forecast of power produced from Customer-owned Distributed Generation;
    - vi. An evaluation of the model used by the Load-Serving Entity to forecast load and its accuracy;
    - vii. A comparison of previous Load Forecasts with the current Load Forecast and demand; and
    - viii. A description of the Load-Serving Entity's existing resources and the ability of those resources to meet the forecasted load.
  - b. An assessment of the Load-Serving Entity's resource needs which, at minimum, shall include:
    - i. The identification of current and future Capacity and energy requirements resulting from the expected or contractual retirement of existing supply and demand-side resources.



- ii. The expected Planning Reserve Margin to be used to maintain reliable service over the Planning Period and a description detailing why it is reasonable.
  - iii. A description of the methodology used to establish the Planning Reserve Margin.
  - iv. A table which lists, by year, through the Planning Period, the expected capacity of each existing supply-side and demand-side resource, the load requirements, and the Planning Reserve Margin.
6. A description of the Load-Serving Entity's Supply-Side Resources, which shall include:
- a. The Load-Serving Entity's fuel procurement strategy;
  - b. A summary of supply-side technologies and benefits;
  - c. A summary of future resource options;
  - d. A summary of the Load-Serving Entity's participation in any energy markets;
  - e. A description of the Load-Serving Entity's resource adequacy strategy; and
  - f. A list and description of Supply-Side Resources that the Load-Serving Entity selected from the results of its All-Source RFP.
7. A description of the Load-Serving Entity's Demand-Side Resources, which shall include:
- a. A summary of all DSM Programs in effect and their corresponding costs and benefits;
  - b. An update on DSM savings achieved since the Load-Serving Entity's last IRP;
  - c. A plan describing how the Load-Serving Entity will develop and encourage DSM Programs using Customer-owned Distributed Generation;
  - d. A description of Energy Efficiency programs in effect and their corresponding costs and benefits;
  - e. A plan detailing the Load-Serving Entity's goal to meet a portion of its Load Forecast using Demand-Side Resources; and
  - f. A summary of future Demand-Side Resource technologies.
8. A description of the Load-Serving Entity's transmission planning activities, which shall include:
- a. An explanation of the need for and purpose of all expected new or Refurbished transmission facilities;
  - b. Incorporation of the Load-Serving Entity's most recent transmission plan filed under A.R.S. § 40-360.02(A) and any relevant provisions of the Commission's most recent Biennial

Transmission Assessment decision regarding the adequacy of transmission facilities in Arizona;

- c. A summary of relevant transmission changes, at the state or regional level, that have affected the Load-Serving Entity's resource planning activities since the most recent Biennial Transmission Assessment decision; and
- d. A comprehensive plan to reduce the need for additional transmission infrastructure;
- 9. A description of the Load-Serving Entity's distribution planning activities, which shall include:
  - a. A Planning Period forecast of Distributed Generation by Customers of the Load-Serving Entity, in terms of annual peak production (megawatts) and annual energy production (megawatt-hours);
  - b. A Planning Period forecast of the Total Costs of the Distributed Generation identified under subsection (9)(a);
  - c. Documentation supporting the analysis of Distributed Generation under subsection (9)(a) and (b);
  - d. A summary of evolving distribution system technologies that have the potential to assist the Load-Serving Entity in meeting demand;
  - e. An analysis of current and forecasted distribution system technologies' ability to meet forecasted demand;
  - f. A plan describing how Distributed Generation connected to the Load-Serving Entity's distribution system can be utilized to meet current and future demand;
  - g. A summary of programs being considered or developed by the Load-Serving Entity to encourage the use of Customer-owned Distributed Generation to meet current and future demand;
  - h. A summary of any and all initiatives to perform Hosting Capacity analyses of the Load-Serving Entity's distribution systems; and
  - i. An assessment of areas of the Load-Serving Entity's distribution system that may be vulnerable to outages due to high Coincident Peak or energy demand, lack of adequate resources, or an Emergency;

10. A summary concerning environmental regulations to which the Load-Serving Entity is subject, which shall, at a minimum, include:
- a. The actual and forecasted costs of compliance with existing and expected environmental regulations;
  - b. Any analysis the Load-Serving Entity has performed in anticipation of potential new or enhanced environmental regulations;
  - c. Identification of the annual emissions from each energy resource; and
  - d. A summary of the environmental compliance requirements for each Generating Unit and purchased power source;
  - e. An analysis of the Load-Serving Entity's water consumption impacts from power production, which shall, at a minimum, include:
    - i. The average annual water consumption of each of the Load-Serving Entity's resources;
    - ii. The sources of supplied water;
    - iii. A forward-looking discussion regarding the security of the supply of water for use in power production;
    - iv. Forecasted water consumption over the Planning Period.
  - f. A plan for reducing environmental impacts related to water consumption, air emissions, and solid waste.
11. A summary of analyses performed by the Load-Serving Entity for managing risk and uncertainty, which shall, at a minimum, include:
- a. Analyses to identify and assess errors, risks, and uncertainties in the following, completed using methods such as Sensitivity Analysis and Probabilistic Analysis:
    - i. Demand forecasts;
    - ii. The costs of Demand-Side Resources and Supply-Side Resources;
    - iii. The availability of sources of power;
    - iv. The costs of compliance with existing environmental regulations;
    - v. Any analysis by the Load-Serving Entity in anticipation of potential new or enhanced environmental regulations;
    - vi. Changes in fuel prices and availability;

- vii. Construction costs, Capital costs, and operating costs; and
    - ix. Other factors the Load-Serving Entity wishes to consider;
  - b. A description and analysis of available means for managing the errors, risks, and uncertainties identified and analyzed in subsection (11)(a), such as obtaining additional information, limiting risk exposure, using incentives, creating additional options, incorporating flexibility, and participating in regional generation and transmission projects;
  - c. A plan to manage the errors, risks, and uncertainties identified and analyzed in subsection (11)(a).
  - d. A description of the IRP scenarios that were developed and evaluated to identify and assess errors, risk and uncertainties; and
  - e. A description of the IRP scenario selected by the Load-Serving Entity and the reason for its selection;
- 12. A summary of portfolio analyses performed by the Load-Serving Entity which shall, at a minimum, include:
  - a. A retirement portfolio analysis which includes:
    - i. Identification of each power source or Generating Unit that is planned to be retired, discontinued, Decommissioned, Mothballed, or Derated;
    - ii. The costs and spending schedule for each retirement, discontinuation, Decommissioning, Mothballing, or Derating;
    - iii. The reasons for each retirement, discontinuation, Decommissioning, Mothballing, or Derating;
    - iv. Identification of least-cost replacement Capacity; and
    - v. Evaluation of retirement portfolios and a description of the selected retirement portfolio;
  - b. An analysis of a wide range of resource portfolios that could address the resource needs that have been identified for the Planning Period, which includes:
    - i. Documentation of the data, assumptions, and methods or models used to forecast Production Costs and power production, including the method by which the forecast was Benchmarked;
    - ii. Cost analyses and cost projections for each resource analyzed;

- iii. The Capital cost, construction time, and construction spending schedule for each Generating Unit expected to be new or Refurbished during the period;
- iv. The environmental impacts of each resource;
- v. The water consumption requirements of each resource;
- vi. A description of each potential power source that was rejected, along with the Capital costs, operating costs, and maintenance costs of each rejected source and an explanation of the reasons for rejecting each source;
- vii. The delivered cost of all resource options, including costs associated with environmental compliance, system integration, backup Capacity, and transmission delivery;
- viii. Data to support the Load-Serving Entity's technology choices for Supply-Side Resources;
- ix. A description of each resource portfolio, including a load and resources table summarizing the resource portfolio; and
- x. An executive summary of each resource portfolio that was analyzed.
- c. The Load-Serving Entity's selection of its Preferred Resource Plan to meet the Planning Period forecasted load based upon comprehensive consideration of a wide range of Supply-Side Resource and Demand-Side Resource options that shall:
  - i. Result in the Load-Serving Entity's Reliably serving the demand for electric energy services;
  - ii. Address the adverse environmental impacts of power production;
  - iii. Address water consumption impacts of power production;
  - iv. Effectively manage the uncertainty and risks associated with costs, environmental impacts, Load Forecasts, and other factors;
  - v. Achieve reasonable Total Costs over the Planning Period forecasted period, taking into consideration the objectives set forth in subsections (12)(c)(i) through (iv); and
  - vi. Contain all of the following:
    - a. A complete description and documentation of the resource portfolio, including supply and demand conditions, availability of transmission, costs, and Discount Rates utilized;
    - b. A comprehensive, self-explanatory load and resources table summarizing the resource portfolio; and

c. An executive summary;

13. A description of the efforts the Load-Serving Entity has made towards Customer engagement, which shall include:

a. An outline of the timing and extent of public participation and of the advisory group meetings the Load-Serving Entity has engaged in while developing its IRP; and

b. An executive summary describing:

i. How the Load-Serving Entity has engaged its Customers throughout the development of its IRP; and

ii. All Customer programs in effect that are relevant to the resource planning process.

14. An index to indicate how the Load-Serving is complying with the provisions of this Article; and

15. A definitions section that defines relevant terms used within the Load-Serving Entity's IRP.

C. If a Load-Serving Entity's IRP does not contain sufficient information to allow Staff to analyze the IRP fully for compliance with this Article, Staff shall request:

a. Additional information from the Load-Serving Entity, which may include the data used in the Load-Serving Entity's analyses;

b. Additional analyses to be performed by the Load-Serving Entity to improve specified components of the IRP; and

c. That the Load-Serving Entity provide reasonable access to any modeling software relied upon by the Load-Serving Entity in the development of its IRP.

D. A Load-Serving Entity shall, upon submission of its IRP, submit to Staff all supplemental information relied upon in the development of the proposed IRP such as work papers and references to external and internal source documents.

#### **R14-2-2708. Load-Serving Entity Annual Reporting Requirements**

A. A Load-Serving Entity shall, by October 1 of each year, beginning on , October 1, 2022, file with the Commission a report that shall include the following items of Demand-Side Resource data, including for each item for which no record is maintained the Load-Serving Entity's best estimate and a full description of how the estimate was made:

1. Average hourly demand for the previous calendar year, disaggregated by:

a. Sales to end users;



- b. Sales for resale;
    - c. Energy losses; and
    - d. Other disposition of energy, such as energy furnished without charge and energy used by the Load-Serving Entity;
  - 2. Coincident Peak demand and energy consumption by month for the previous Planning Period, disaggregated by Customer Class;
  - 3. Average number of annual Customers by Customer Class for each of the previous Planning Period; and
  - 4. Reduction in load (kilowatt and kilowatt-hours) in the previous calendar year due to existing demand management measures, by type of demand management measure.
- B. A Load-Serving Entity shall, by October 1 of each year, beginning October 1, 2022, file with the Commission a report that shall include the following items of supply-side data, including for each item for which no record is maintained the Load-Serving Entity's best estimate and a full description of how the estimate was made:
- 1. For each Generating Unit and purchased power contract for the previous calendar year:
    - a. In-Service Date and the expected time period or contract period during which the Supply-Side Resource will be available for use by the Load-Serving Entity;
    - b. The type of Generating Unit or contract;
    - c. The Load-Serving Entity's share of the Generating Unit's Capacity, or of Capacity under the contract, in megawatts;
    - d. The maximum Generating Unit or contract Capacity, by hour, day, or month, if such Capacity varies during the year;
    - e. The annual Capacity Factor;
    - f. The average Heat Rate of the Generating Unit and, if available, its Heat Rates at selected output levels;
    - g. The average fuel cost for Generating Unit, in dollars per million Btu for each type of fuel;
    - h. Other variable operating and maintenance costs for the Generating Unit, in dollars per megawatt hour;

- i. The purchased power energy costs for each contract exceeding three calendar years, in dollars per megawatt-hour;
- j. The fixed operating and maintenance costs of the Generating Unit, in dollars per megawatt;
- k. The demand charges for purchased power;
- l. The fuel type for each Generating Unit;
- m. The minimum Capacity at which the Generating Unit would be run, or purchased power is needed, if applicable;
- n. Whether, under standard operating procedures, the Generating Unit must be run if it is available to run;
- o. The description of each Generating Unit as base load, intermediate, or peaking;
- p. The environmental impacts, including air emission quantities (in metric tons or pounds) and rates (in quantities per megawatt-hour) for carbon dioxide, nitrogen oxides, sulfur dioxide, mercury, particulates, and other air emissions subject to current or expected future environmental regulation;
- q. The water consumption quantity and rate; and
- r. The amount of coal ash (by ton) produced per Generating Unit;
- 2. For the Supply-Side Resource in the previous calendar year:
  - a. A description of Generating Unit commitment procedures;
  - b. Production Costs;
  - c. Reserve Requirements;
  - d. Spinning Reserve;
  - e. Reliability of the generating, transmission, and distribution systems;
  - f. Purchase and sale prices, averaged by month, for the aggregate of all purchases and sales-related contracts with a duration of less than three calendar years; and
  - g. Energy Losses;
- 3. The total Capacity of Distributed Generation in the Load-Serving Entity's service area for the previous calendar year; and

4. An explanation of any resource procurement processes, in accordance with R14-2-2713, undertaken by the Load-Serving Entity during the previous calendar year that did not include use of an RFP, including the exception under which the process was used.

C. A Load-Serving Entity shall file, by May 1 of each year, beginning May 1, 2024, an annual Procurement Activity Report that specifies, at minimum, the following:

1. The procurement activities the Load-Serving Entity plans to undertake in the following calendar year to effectuate its Commission-approved Action Plan;
2. All associated cost information related to the Load-Serving Entity's planned procurement activities; and
3. A timeline describing each planned procurement activity.

**R14-2-2709. Public Advisory Process**

A. Within 90 calendar days following Commission determination of its Action Plan, a Load-Serving Entity shall submit to the Commission, for the following IRP, a report for compliance which includes the following information:

- a. The identification of a Stakeholder Advisory Group; including all participants, organizations, and affiliations of each member;
- b. A summary of how the Load-Serving Entity envisions the Stakeholder Advisory Group will contribute to the development of its IRP;
- c. The date of its first Stakeholder Advisory Group meeting; and
- d. A preliminary timeline of opportunities for the public to participate in the Load-serving Entity's IRP process.

B. A Load-Serving Entity may, at minimum, consider the input of the Stakeholder Advisory Group as it relates to the development of the following:

- a. The Load-Serving Entity's Load Forecast;
- b. Technology costs and assumptions;
- c. Economic scenarios; and
- d. Resource portfolios.

C. A Load-Serving Entity may conduct regular meetings with its Stakeholder Advisory Group throughout the IRP process.

D. A Load-Serving Entity may solicit, consider, and timely respond to relevant input relating to the development of the Load-Serving Entity's IRP by an interested party.

**R14-2-2710. Electric Energy Efficiency**

A. An Electric Utility shall include in its Energy Efficiency Report the following information regarding the Demand-Side Resource used by the Electric Utility:

1. A list of the Electric Utility's current Demand-Side Resources, disaggregated by Customer Class;
2. For each Demand-Side Resource:
  - a. A brief description;
  - b. The purpose, objectives, and savings targets;
  - c. For the previous three calendar years:
    - i. The level of Customer participation;
    - ii. The Total Cost incurred, disaggregated by type of cost, such as administrative costs, rebates, and monitoring costs;
    - iii. A description and the results of evaluation and monitoring activities;
  - d. Savings realized, in an appropriate metric (kW, kWh, therms, and Btu);
  - e. The Environmental Benefits realized, including reduced emissions and water savings;
  - f. Incremental Benefits and net benefits, in dollars;
  - g. Performance-incentive calculations for the previous three calendar years;
  - h. Problems encountered during the previous three calendar years and proposed solutions;
  - i. A description of any modifications proposed for the next three calendar years; and
  - j. Whether the Electric Utility proposes to terminate the Demand-Side Resource and, if so, the proposed date of termination; and
3. A description of the findings from any research projects ordered by the Commission and completed during the previous three calendar years.

B. An Electric Utility shall design each Demand-Side Resource:

1. To be Cost-Effective; and
2. To accomplish at least one of the following:
  - a. Provide Energy Efficiency;
  - b. Manage energy consumption;

- c. Reduce peak demand; or
- d. Alter Customer energy consumption behavior.

C. An Electric Utility shall consider the following when planning and implementing a Demand-Side Resource:

- 1. Whether the Demand-Side Resource will achieve Cost-Effective energy savings and peak demand reductions;
- 2. Whether the Demand-Side Resource will advance market transformation and achieve sustainable savings, reducing the need for future market interventions;
- 3. Whether the Electric Utility can ensure a level of funding adequate to sustain the Demand-Side Resource and allow the Demand-Side Resource to achieve its targeted goal; and
- 4. Whether the Electric Utility can allocate a portion of Demand-Side Resource specifically to Limited-Income Customers.

D. An Electric Utility shall provide an opportunity for all Electric Utility Customer Classes to participate in Demand-Side Resources, with a portion specifically allocated for Limited-Income Customers.

E. An Electric Utility shall monitor and evaluate each Demand-Side Resource to determine whether it is Cost-Effective and otherwise meets expectations and report any unintended consequences to the Commission in its Energy Efficiency Report.

F. An Electric Utility may recover the costs that it incurs in planning, designing, implementing, and evaluating a Demand-Side Resource if the Commission approves such cost recovery for the Electric Utility in a rate process.

G. Staff may request an Electric Utility to perform analyses of a specified Demand-Side Resource to comply with this Article.

**R14-2-2711. Gas Energy Efficiency**

A. A Gas Utility may, by April 1 every third year, beginning April 1, 2023, file with the Commission, for review and approval, an Energy Efficiency Report describing each Demand-Side Resource designed to reduce Coincident Peak and energy demand, disaggregated by Customer Class and:

- 1. Proposed to be implemented by the Gas Utility, during the next three calendar years;
- 2. Currently implemented by the Gas Utility; and
- 3. Proposed to be modified or discontinued by the Gas Utility.

**B. A Gas Utility shall include in its Energy Efficiency Report the following information regarding the Demand-Side Resource used by the Gas Utility:**

1. A list of the Gas Utility's current Demand-Side Resources, disaggregated by Customer Class;
2. For each Demand-Side Resource:
  - a. A brief description;
  - b. The purpose, objectives, and savings targets;
  - c. For the previous three calendar years:
    - i. The level of Customer participation;
    - ii. The Total Cost incurred, disaggregated by type of cost, such as administrative costs, rebates, and monitoring costs;
    - iii. A description and the results of evaluation and monitoring activities;
  - d. Savings realized, in an appropriate metric (kW, kWh, therms, and Btu);
  - e. The Environmental Benefits realized, including reduced emissions and water savings;
  - f. Incremental Benefits and net benefits, in dollars;
  - g. Performance-incentive calculations for the previous three calendar years;
  - h. Problems encountered during the previous three calendar years and proposed solutions;
  - i. A description of any modifications proposed for the next three calendar years; and
  - j. Whether the Gas Utility proposes to terminate the Demand-Side Resource and, if so, the proposed date of termination; and
3. A description of the findings from any research projects ordered by the Commission and completed during the previous three calendar years.

**C. A Gas Utility shall design each Demand-Side Resource:**

1. To be Cost-Effective; and
2. To accomplish at least one of the following:
  - a. Provide Energy Efficiency;
  - b. Manage energy consumption;
  - c. Reduce peak demand; or
  - d. Alter Customer energy consumption behavior.

**D. A Gas Utility shall consider the following when planning and implementing a Demand-Side Resource:**



1. Whether the Demand-Side Resource will achieve Cost-Effective energy savings and peak demand reductions;
2. Whether the Demand-Side Resource will advance market transformation and achieve sustainable savings, reducing the need for future market interventions;
3. Whether the Gas Utility can ensure a level of funding adequate to sustain the Demand-Side Resource and allow the Demand-Side Resource to achieve its targeted goal; and
4. Whether the Gas Utility can allocate a portion of Demand-Side Resource specifically to Limited-Income Customers.

E. A Gas Utility shall provide an opportunity for all Gas Utility Customer Classes to participate in Demand-Side Resources, with a portion specifically allocated for Limited-Income Customers.

F. A Gas Utility shall monitor and evaluate each Demand-Side Resource to determine whether it is Cost-Effective and otherwise meets expectations and report any unintended consequences to the Commission in its Energy Efficiency Report.

G. A Gas Utility may recover the costs that it incurs in planning, designing, implementing, and evaluating a Demand-Side Resource if the Commission approves such cost recovery for the Gas Utility in a rate process.

H. Staff may request a Gas Utility to perform analyses of a specified Demand-Side Resource to comply with this Article.

**R14-2-2712. Commission Review and Approval**

A. Within 180 calendar days after an Electric Utility files its Clean Energy Implementation Plan, Staff shall file a report that contains Staff's analysis, conclusions, and recommendations for the Commission's consideration.

B. The Commission may hold a hearing based on Staff's report under subsection (A) to determine whether an Electric Utility's Clean Energy Implementation Plan satisfies the requirements of this Article.

C. Within 90 calendar days after a Load-Serving Entity files its Preliminary IRP, Staff shall file a report that contains Staff's analysis, conclusions, and recommendations regarding the Load-Serving Entity's Load Forecast.

D. Within 60 calendar days after Staff files its report under subsection (C), the Commission shall issue:

1. An order of Approval of the Load-Serving Entity's Load Forecast stating the reason(s) for Approval; or
  2. An order of no Approval of the Load-Serving Entity's Load Forecast stating the reason(s) for no Approval.
- E. Within 180 calendar days after a Load-Serving Entity files its IRP, Staff shall file a report that contains Staff's analysis, conclusions, and recommendations regarding the Load-Serving Entity's IRP.
- F. Within 60 calendar days after Staff files its report under subsection (E), the Commission shall issue an order for the Load-Serving Entity's IRP which shall include:
1. An order of Acknowledgment, stating the reasons for Acknowledgment, if the Commission determines that the IRP, as amended if applicable, complies with the requirements of this Article and that the Load-Serving Entity's IRP is reasonable and in the public interest, based on Good Utility Practice and considering the applicable factors in subsection (G); or
  2. An order of no Acknowledgment stating the reason(s) for no Acknowledgment, if the Commission does not make the determination described in subsection (F)(1); and
  3. Either an order of Approval or an order of no Approval of the Load-Serving Entity's Action Plan, stating the reason(s) for approval or no Approval based on Good Utility practice and considering the applicable factors in subsection (G).
- G. In making the determination described in subsection (F)(1), the Commission shall consider:
1. The Total Cost of energy services;
  2. The degree to which the factors that affect demand, including demand management, have been taken into account;
  3. The degree to which Supply-Side Resource alternatives, such as Distributed Generation, have been taken into account;
  4. 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;
  5. The Reliability of power supplies, including fuel diversity and non-cost considerations;
  6. The Reliability of the transmission grid;

7. The degree to which the Load-Serving Entity considered all relevant resources, risks, and uncertainties;
  8. The degree to which the Load-Serving Entity's plan for future resources is in the best interest of its Customers;
  9. The best combination of expected costs and associated risks for the Load-Serving Entity and its Customers; and
  10. The degree to which the Load-Serving Entity's IRP allows for coordinated efforts with other Load-Serving Entities.
- H. The Commission may hold a hearing or workshop regarding a Load-Serving Entity's IRP. If the Commission holds such a hearing or workshop, the Commission may extend the deadline for the Commission to issue an order under subsection (F).
- I. While no particular future ratemaking treatment is implied by or shall be inferred from the Commission's Acknowledgment or lack of Acknowledgment, the Commission shall consider a Load-Serving Entity's filings made in accordance with this Article when the Commission evaluates the performance of the Load-Serving Entity in subsequent rate cases and other proceedings.
- J. A Load-Serving Entity may seek Commission Approval of specific resource planning actions.
- K. A Load-Serving Entity may file a supplement to an approved Action Plan if changes in Resource Procurement Actions, conditions, or assumptions necessitate a material change in the Load-Serving Entity's Action Plan before the next IRP is due to be filed.
- L. Within 60 calendar days after a Load-Serving Entity files its annual Procurement Activity Report, Staff may file objections for the Commission's consideration.
- M. A Load-Serving Entity shall include any request to update its Action Plan in its annual Procurement Activity Report.
- N. Within 60 days after a Load-Serving Entity's request to update its Action Plan, the Commission shall issue:
1. An order of Approval of the Load-Serving Entity's request to update its Action Plan; or
  2. An order denying the Load-Serving Entity's request to update its Action Plan.

- O. Within 180 calendar days after a Gas Utility files its Energy Efficiency Report, Staff shall file a report that contains Staff's analysis, conclusions, and recommendations for the Commission's consideration.
- P. The Commission may hold a hearing based on Staff's report under subsection (O) and may issue an order based on Staff's analysis of a Gas Utility's Energy Efficiency Report to determine whether the Gas Utility's Energy Efficiency Report satisfies the requirements of this Article.

**R14-2-2713. Resource Procurement**

- A. Except as provided in subsection (B), a Load-Serving Entity may use the following procurement methods for the wholesale acquisition of energy or Capacity and for physical power hedge transactions:
1. Purchase through a third-party on-line trading system;
  2. Purchase from a third-party independent energy broker;
  3. Purchase from a non-Affiliated entity through auction or an RFP process;
  4. Bilateral contract with a non-Affiliated entity;
  5. Bilateral contract with an Affiliated entity, provided that non-Affiliated entities were provided notice and an opportunity to compete against the Affiliated entity's proposal before the transaction was executed; and
  6. Any other competitive procurement process approved by the Commission.
- B. A Load-Serving Entity shall use an All-Source RFP process as its primary acquisition process for the wholesale acquisition of energy and Capacity, unless one of the following exceptions applies:
1. The Load-Serving Entity is experiencing an Emergency;
  2. The Load-Serving Entity needs to make an immediate acquisition to maintain system Reliability;
  3. The Load-Serving Entity needs to acquire other components of energy procurement, such as fuel, fuel transportation, and transmission projects;
  4. The Load-Serving Entity's planning horizon is two years or less;
  5. The transaction presents the Load-Serving Entity a genuine, unanticipated opportunity to acquire a Supply-Side Resource or Demand-Side Resource at a clear and significant discount, compared to the cost of acquiring new Generating Units, and will provide unique value to the Load-Serving Entity's Customers;

6. The transaction is necessary for the Load-Serving Entity to satisfy an obligation under is Article;  
or

7. The transaction is necessary for the Load-Serving Entity's Supply-Side Resource.

C. Upon receiving Approval of its Preliminary IRP, a Load-Serving Entity shall:

1. Collaborate with interested stakeholders to develop its All-Source RFPs;

2. Issue the All-Source RFPs to address its Approved Load Forecast and any other resource needs;

3. Utilize the results of its All-Source RFPs in the development of each portfolio to be analyzed in its IRP;

4. Report the results of its All-Source RFPs in its IRP; and

5. Report the resource selections in its Action Plan.

D. The Load-Serving Entity's All-Source RFP shall identify the specific needs to be satisfied, and shall be technology neutral, location-neutral, and size-neutral.

E. The Load-Serving Entity's All-Source RFP shall consider Demand-Side Resources and Supply-Side Resources on a non-discriminatory basis.

F. A Load-Serving Entity shall engage an Independent Monitor, approved by the Commission, to oversee all RFP processes for procurement of new resources.

**R14-2-2714. Independent Monitor Selection and Responsibilities**

A. When a Load-Serving Entity contemplates engaging in an RFP process, the Load-Serving Entity shall consult with Staff regarding the identity of companies or consultants that could serve as independent Monitor for the RFP process.

B. After consulting with Staff, a Load-Serving Entity shall create a vendor list of three to five candidates to serve as Independent Monitor and shall file the vendor list with the Commission to allow interested persons time to review and file objections to the vendor list.

C. An interested person shall file with the Commission, within 30 days after a vendor list is filed with the Commission, any objection that the interested person may have to a candidate's inclusion on a vendor list.

D. Within 60 days after a vendor list is filed with the Commission, Staff shall issue a notice identifying each candidate on the vendor list that Staff considers to be qualified to serve as Independent Monitor for the contemplated RFP process. In making its determination, Staff shall consider the experience of

the candidates, the professional reputation of the candidates, and any objections filed by interested persons.

E. A Load-Serving Entity may retain any of the candidates identified in Staff's notice as an Independent Monitor for the contemplated RFP process.

F. A Load-Serving Entity shall file with the Commission a written notice of its retention of an Independent Monitor.

G. A Load-Serving Entity is responsible for paying the Independent Monitor for its services and may charge a reasonable bidder's fee to each bidder in the RFP process to help offset the cost of the Independent Monitor's services.

H. At least one week prior to the deadline for submitting bids, a Load-Serving Entity shall provide the Independent Monitor a copy of any bid proposal prepared by the Load-Serving Entity or an entity Affiliated with the Load-Serving Entity and of any Benchmark or reference cost the Load-Serving Entity has developed for use in evaluating bids. The Independent Monitor shall take steps to secure the Load-Serving Entity's bid proposal and any Benchmark-based costs or reference cost so that they are inaccessible to any bidder, the Load-Serving Entity, and any entity Affiliated with the Load-Serving Entity.

**R14-2-2715. Confidential Information**

A. If a Utility believes that a reporting requirement pursuant to this Article may result in disclosure of confidential business data or confidential energy infrastructure information, the Utility shall file with the Commission:

1. A public version of the reporting requirement pursuant to this Article, from which all data or information considered to be confidential has been redacted; and
2. A request to submit the data or information that is considered to be confidential to Staff be submitted pursuant to a confidentiality agreement, which shall cite each statute or rule supporting the confidential treatment of the data or information.

B. Data and information protected by a confidentiality agreement shall not be filed with the Commission and shall not be open to public inspection or otherwise made public except upon an order of the Commission entered after written notice to the Utility and upon finding of good cause for disclosure.

**R14-2-2716. Waivers and Exemptions**



- A. The Commission may waive compliance with any provision of this Article or exempt a Utility from complying with any provision in this Article upon a finding that good cause exists for granting such waiver or exemption and that it will not harm public interest.
- B. A Utility requesting an exemption or waiver of any provision in this Article shall file with the Commission an application that includes, at a minimum:
  - 1. The reasons why the burden of compliance with the Article, or the specific provision in the Article for which exemption is requested, exceeds the potential benefits to Customers that would result from compliance with the provisions pursuant to this Article;
  - 2. Data supporting the Electric Utility's or Gas Utility's assertions' as to the burden of compliance and the potential benefits to Customers that would result from compliance; and
  - 3. The reasons why the public interest would be served or would not be harmed by the requested exemption.

**R14-2-2717. Cooperatives**

- A. A Cooperative or Load-Serving Cooperative shall employ best reasonable efforts in accordance with Good Utility Practice to comply with the applicable provisions of this Article.
- B. Upon Commission Approval of a Cooperative's Clean Energy Implementation Plan, the provisions of the Clean Energy Implementation Plan shall substitute for the requirements set forth in subsection R14-2-2705 (B).
- C. A Load-Serving Cooperative shall submit to the Commission whatever information, data, criteria, and studies the Load-Serving Cooperative has used in its analysis of its Planning Period.
- D. Upon Commission Acknowledgment of a Load-Serving Cooperative's IRP filing, and Approval of its Action Plan, its provisions shall substitute for the requirements set forth in Sections R14-2-2705, R14-2-2706, R14-2-2708, R14-2-2709, and R14-2-2712 (C) and (D).

**R14-2-2718. Commission Enforcement**

- A. No provision of this Article shall limit the actions the Commission may take or the penalties the Commission may impose pursuant to Arizona Constitution Article 15 §§ 16 and 19 and Arizona Revised Statutes, Title 40, Chapter 2, Article 9.
- B. Prior to Commission action or imposition of penalties, a Utility is entitled to notice and an opportunity to be heard.

**R14-2-2719. Cost Recovery and Prudency**

- A. Except as provided in subsection (C), a Utility may recover its prudently incurred costs of complying with the provisions of this Article in a rate process.
- B. If the Commission finds that a Utility has failed to comply with this Article, the Commission shall provide the Utility notice and an opportunity to be heard.
- C. If the Commission has satisfied subsection (B), the Commission may deny a Utility recovery of its prudently incurred costs in whole or in part, impose any fines or take any other adverse actions against the Utility.

**Appendix A. Integrated Resource Plan Document Structure**

- A. Executive Summary
- B. Planning for the Future
- C. Energy and Demand Forecast
- D. Supply-Side Resources
- E. Demand-Side Resources
- F. Transmission System Planning
- G. Distribution System Planning
- H. Environmental Considerations
- I. Managing Risk and Uncertainty
- J. Portfolio and Plan Analysis
- K. Customer Engagement
- L. Compliance with Rules

**TITLE 14. PUBLIC SERVICE CORPORATIONS; CORPORATIONS AND ASSOCIATIONS;  
SECURITIES REGULATION  
CHAPTER 2. CORPORATION COMMISSION - FIXED UTILITIES  
ARTICLE 23. NET METERING**

Section

R14-2-2302. Definitions

R14-2-2307. Net Metering Tariff

**ARTICLE 23. NET METERING**

**R14-2-2302. Definitions**

12. "Net Metering Customer" means any Arizona Customer who chooses to take electric service in the manner described in the definition of Net Metering in subsection (11) and ~~under the~~ Customer's Electric Utility has a Net Metering tariff for which the Customer would be eligible; ~~as described in R14-2-2307.~~

**R14-2-2307. Net Metering Tariff**

~~A. Each Electric Utility shall file, for approval by the Commission, a Net Metering tariff within 120 days from the effective date of these rules, including financial information and supporting data sufficient to allow the Commission to determine the Electric Utility's fair value for the purposes of evaluating any specific proposed charges. The Commission shall issue a decision on these filings within 120 days.~~

**BA.** If an Electric Utility has a Net Metering tariff, ~~The~~ Net Metering tariff shall specify standard rates for annual purchases of remaining credits from Net Metering Facilities and may specify total utility capacity limits. If total utility capacity limits are included in the tariff, such limits must be fully justified.

**CB.** Electric utilities may include seasonally and time of day differentiated Avoided Cost rates for purchases from Net Metering Customers, to the extent that Avoided Costs vary by season and time of day.

**TITLE 14. PUBLIC SERVICE CORPORATIONS; CORPORATIONS AND ASSOCIATIONS;  
SECURITIES REGULATION  
CHAPTER 2. CORPORATION COMMISSION  
FIXED UTILITIES**

**~~ARTICLE 7. RESOURCE PLANNING AND PROCUREMENT~~**

Section

- ~~R14-2-701. — Definitions~~  
~~R14-2-702. — Applicability~~  
~~R14-2-703. — Load-serving entity reporting requirements~~  
~~R14-2-704. — Commission review of load-serving entity resource plans~~  
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~~R14-2-706. — Independent Monitor Selection and Responsibilities~~

**~~ARTICLE 7. RESOURCE PLANNING AND PROCUREMENT~~**

**~~R14-2-701. — Definitions~~**

~~In this Article, unless otherwise specified:~~

- ~~1. — “Acknowledgment” means a Commission determination, under R14-2-704, that a plan meets the basic requirements of this Article.~~
- ~~2. — “Affiliated” means related through ownership of voting securities, through contract, or otherwise in such a manner that one entity directly or indirectly controls another, is directly or indirectly controlled by another, or is under direct or indirect common control with another entity.~~
- ~~3. — “Benchmark” means to calibrate against a known set of values or standards.~~
- ~~4. — “Book life” means the expected time period over which a power supply source will be available for use by a load-serving entity.~~
- ~~5. — “Btu” means British thermal unit.~~
- ~~6. — “Capacity” means the amount of electric power, measured in megawatts, that a power source is rated to provide.~~
- ~~7. — “Capital costs” means the construction and installation cost of facilities, including land, land rights, structures, and equipment.~~

8. —“Coincident peak” means the maximum of the sum of two or more demands that occur in the same demand interval, which demand interval may be established on an annual, monthly, or hourly basis.
9. —“Customer class” means a subset of customers categorized according to similar characteristics, such as amount of energy consumed; amount of demand placed on the energy supply system at the system peak; hourly, daily, or seasonal load pattern; primary type of activity engaged in by the customer, including residential, commercial, industrial, agricultural, and governmental; and location.
10. —“Decommissioning” means the process of safely and economically removing a generating unit from service.
11. —“Demand management” means beneficial reduction in the total cost of meeting electric energy service needs by reducing or shifting in time electricity usage.
12. —“Derating” means a reduction in a generating unit’s capacity.
13. —“Discount rate” means the interest rate used to calculate the present value of a cost or other economic variable.
14. —“Docket Control” means the office of the Commission that receives all official filings for entry into the Commission’s public electronic docketing system.
15. —“Emergency” means an unforeseen and unforeseeable condition that:
  - a. — Does not arise from the load serving entity’s failure to engage in good utility practices,
  - b. — Is temporary in nature, and
  - c. — Threatens reliability or poses another significant risk to the system.
16. —“End use” means the final application of electric energy, for activities such as, but not limited to, heating, cooling, running an appliance, or motor, an industrial process, or lighting.
17. —“Energy losses” means the quantity of electric energy generated or purchased that is not available for sale to end users, for resale, or for use by the load-serving entity.
18. —“Escalation” means the change in costs due to inflation, changes in manufacturing processes, changes in availability of labor or materials, or other factors.
19. —“Generating unit” means a specific device or set of devices that converts one form of energy (such as heat or solar energy) into electric energy, such as a turbine and generator or a set of photovoltaic cells.



20. — ~~“Heat rate” means a measure of generating station thermal efficiency expressed in Btus per net kilowatt hour and computed by dividing the total Btu content of fuel used for electric generation by the kilowatt hours of electricity generated.~~
21. — ~~“Independent monitor” means a company or consultant that is not affiliated with a load-serving entity and that is selected to oversee the conduct of a competitive procurement process under R14-2-706.~~
22. — ~~“Integration” means methods by which energy produced by intermittent resources can be incorporated into the electric grid.~~
23. — ~~“Intermittent resources” means electric power generation for which the energy production varies in response to naturally occurring processes like wind or solar intensity.~~
24. — ~~“Interruptible power” means power made available under an agreement that permits curtailment or cessation of delivery by the supplier.~~
25. — ~~“In-service date” means the date a power supply source becomes available for use by a load-serving entity.~~
26. — ~~“Load-serving entity” means a public service corporation that provides electricity generation service and operates or owns, in whole or in part, a generating facility or facilities with capacity of at least 50 megawatts combined.~~
27. — ~~“Long term” means having a duration of three or more years.~~
28. — ~~“Maintenance” means the repair of generation, transmission, distribution, administrative, and general facilities; replacement of minor items; and installation of materials to preserve the efficiency and working condition of the facilities.~~
29. — ~~“Mothballing” means the temporary removal of a generating unit from active service and accompanying storage activities.~~
30. — ~~“Operate” means to manage or otherwise be responsible for the production of electricity by a generating facility, whether that facility is owned by the operator, in whole or in part, or by another entity.~~
31. — ~~“Participation rate” means the proportion of customers who take part in a specific program.~~
32. — ~~“Probabilistic analysis” means a systematic evaluation of the effect, on costs, reliability, or other measures of performance, of possible events affecting factors that influence performance, considering the likelihood that the events will occur.~~

33. — “Production cost” means the variable operating costs and maintenance costs of producing electricity through generation plus the cost of purchases of power sufficient to meet demand.
34. — “Refurbish” means to make major changes, more extensive than maintenance or repair, in the power production, transmission, or distribution characteristics of a component of the power supply system, such as by changing the fuels that can be used in a generating unit or changing the capacity of a generating unit.
35. — “Reliability” means a measure of the ability of a load-serving entity’s generation, transmission, or distribution system to provide power without failures to reflect the portion of time that a system is unable to meet demand or the kilowatt-hours of demand that could not be supplied.
36. — “Renewable energy resource” means an energy resource that is replaced rapidly by a natural, ongoing process and that is not nuclear or fossil fuel.
37. — “Reserve requirements” means the capacity that a load-serving entity must maintain in excess of its peak load to provide for scheduled maintenance, forced outages, unforeseen loads, emergencies, system operating requirements, and reserve sharing arrangements.
38. — “Reserve sharing arrangement” means an agreement between two or more load-serving entities to provide backup capacity.
39. — “Resource planning” means integrated supply and demand analyses completed as described in this Article.
40. — “RFP” means request for proposals.
41. — “Self-generation” means the production of electricity by an end user.
42. — “Sensitivity analysis” means a systematic assessment of the degree of response of costs, reliability, or other measures of performance to changes in assumptions about factors that influence performance.
43. — “Short term” means having a duration of less than three years.
44. — “Spinning reserve” means the capacity a load-serving entity must maintain connected to the system and ready to deliver power promptly in the event of an unexpected loss of generation source, expressed as a percentage of peak load, as a percentage of the largest generating unit, or as in fixed megawatts.
45. — “Staff” means individuals working for the Commission’s Utilities Division, whether as employees or through contract.

46. ~~“Third-party independent energy broker” means an entity, such as Prebon Energy or Tradition Financial Services, that facilitates an energy transaction between separate parties without taking title to the transaction.~~
47. ~~“Third-party on-line trading system” means a computer-based marketplace for commodity exchanges provided by an entity that is not affiliated with the load-serving entity, such as the Interecontinental Exchange, California Independent System Operator, or New York Mercantile Exchange.~~
48. ~~“Total cost” means all capital, operating, maintenance, fuel, and decommissioning costs, plus the costs associated with mitigating any adverse environmental effects, incurred, by end-users, load-serving entities, or others, in the provision or conservation of electric energy.~~

**R14-2-702. ~~Applicability~~**

- A. ~~This Article applies to each load-serving entity, whether the power generated is for sale to end users or is for resale.~~
- B. ~~An electricity public service corporation that becomes a load-serving entity by increasing its generating capacity to at least 50 megawatts combined shall provide written notice to the Commission within 30 days after the increase and shall comply with the filing requirements in this Article within two years after the notice is filed.~~
- C. ~~The Commission may, by Order, exempt a load-serving entity from complying with any provision in this Article, or the Article as a whole, upon determining that:~~
1. ~~The burden of compliance with the provision, or the Article as a whole, exceeds the potential benefits to customers in the form of cost savings, service reliability, risk reductions, or reduced environmental impacts that would result from the load-serving entity’s compliance with the provision or Article; and~~
  2. ~~The public interest will be served by the exemption.~~
- D. ~~A load-serving entity that desires an exemption shall submit to Docket Control an application that includes, at a minimum:~~
1. ~~The reasons why the burden of complying with the Article, or the specific provision in the Article for which exemption is requested, exceeds the potential benefits to customers that would result from the load-serving entity’s compliance with the provision or Article;~~

2. — Data supporting the load-serving entity's assertions as to the burden of compliance and the potential benefits to customers that would result from compliance; and

3. — The reasons why the public interest would be served by the requested exemption.

E. — A load-serving entity shall file with Docket Control, within 120 days after the effective date of these rules, the documents that would have been due on April 1, 2010, under R14-2-703(C), (D), (E), (F), and (H) had the revisions to those subsections been effective at that time.

**~~R14-2-703. — Load-serving entity reporting requirements~~**

A. — A load-serving entity shall, by April 1 of each year, file with Docket Control a compilation of the following items of demand-side data, including for each item for which no record is maintained the load-serving entity's best estimate and a full description of how the estimate was made:

1. — Hourly demand for the previous calendar year, disaggregated by:

a. — Sales to end users;

b. — Sales for resale;

c. — Energy losses; and

d. — Other disposition of energy, such as energy furnished without charge and energy used by the load-serving entity;

2. — Coincident peak demand (megawatts) and energy consumption (megawatt-hours) by month for the previous 10 years, disaggregated by customer class;

3. — Number of customers by customer class for each of the previous 10 years; and

4. — Reduction in load (kilowatt and kilowatt-hours) in the previous calendar year due to existing demand management measures, by type of demand management measure.

B. — A load-serving entity shall, by April 1 of each year, file with Docket Control a compilation of the following items of supply-side data, including for each item for which no record is maintained the load-serving entity's best estimate and a full description of how the estimate was made:

1. — For each generating unit and purchased power contract for the previous calendar year:

a. — In-service date and book life or contract period;

b. — Type of generating unit or contract;

c. — The load-serving entity's share of the generating unit's capacity, or of capacity under the contract, in megawatts;

- d. — ~~Maximum generating unit or contract capacity, by hour, day, or month, if such capacity varies during the year;~~
- e. — ~~Annual capacity factor (generating units only);~~
- f. — ~~Average heat rate of generating units and, if available, heat rates at selected output levels;~~
- g. — ~~Average fuel cost for generating units, in dollars per million Btu for each type of fuel;~~
- h. — ~~Other variable operating and maintenance costs for generating units, in dollars per megawatt hour;~~
- i. — ~~Purchased power energy costs for long term contracts, in dollars per megawatt hour;~~
- j. — ~~Fixed operating and maintenance costs of generating units, in dollars per megawatt;~~
- k. — ~~Demand charges for purchased power;~~
- l. — ~~Fuel type for each generating unit;~~
- m. — ~~Minimum capacity at which the generating unit would be run or power must be purchased;~~
- n. — ~~Whether, under standard operating procedures, the generating unit must be run if it is available to run;~~
- o. — ~~Description of each generating unit as base load, intermediate, or peaking;~~
- p. — ~~Environmental impacts, including air emission quantities (in metric tons or pounds) and rates (in quantities per megawatt hour) for carbon dioxide, nitrogen oxides, sulfur dioxide, mercury, particulates, and other air emissions subject to current or expected future environmental regulation;~~
- q. — ~~Water consumption quantities and rates; and~~
- r. — ~~Tons of coal ash produced per generating unit;~~
- 2. — ~~For the power supply system for the previous calendar year:~~
  - a. — ~~A description of generating unit commitment procedures;~~
  - b. — ~~Production cost;~~
  - c. — ~~Reserve requirements;~~

- d. — ~~Spinning reserve;~~
- e. — ~~Reliability of generating, transmission, and distribution systems;~~
- f. — ~~Purchase and sale prices, averaged by month, for the aggregate of all purchases and sales related to short term contracts; and~~
- g. — ~~Energy losses;~~
- 3. — ~~The level of self generation in the load-serving entity's service area for the previous calendar year; and~~
- 4. — ~~An explanation of any resource procurement processes used by the load-serving entity during the previous calendar year that did not include use of an RFP, including the exception under which the process was used.~~
- C. — ~~A load-serving entity shall, by April 1 of each even year, file with Docket Control a compilation of the following items of load data and analyses, which may include a reference to the last filing made under this subsection for each item for which there has been no change in forecast since the last filing:~~
  - 1. — ~~Fifteen year forecast of system coincident peak load (megawatts) and energy consumption (megawatt-hours) by month and year, expressed separately for residential, commercial, industrial, and other customer classes; for interruptible power; for resale; and for energy losses;~~
  - 2. — ~~Disaggregation of the load forecast of subsection (C)(1) into a component in which no additional demand management measures are assumed, and a component assuming the change in load due to additional forecasted demand management measures; and~~
  - 3. — ~~Documentation of all sources of data, analyses, methods, and assumptions used in making the load forecasts, including a description of how the forecasts were benchmarked and justifications for selecting the methods and assumptions used.~~
- D. — ~~A load-serving entity shall, by April 1 of each even year, file with Docket Control the following prospective analyses and plans, which shall compare a wide range of resource options and take into consideration expected duty cycles, cost projections, other analyses required under this Section, environmental impacts, and water consumption and may include a reference to the last filing made under this subsection for each item for which there has been no change since the last filing:~~



1. ~~A 15-year resource plan, providing for each year:~~
  - a. ~~Projected data for each of the items listed in subsection (B)(1), for each generating unit and purchased power source, including each generating unit that is expected to be new or refurbished during the period, which shall be designated as new or refurbished, as applicable, for the year of purchase or the period of refurbishment;~~
  - b. ~~Projected data for each of the items listed in subsection (B)(2), for the power supply system;~~
  - c. ~~The capital cost, construction time, and construction spending schedule for each generating unit expected to be new or refurbished during the period;~~
  - d. ~~The escalation levels assumed for each component of cost, such as, but not limited to, operating and maintenance, environmental compliance, system integration, backup capacity, and transmission delivery, for each generating unit and purchased power source;~~
  - e. ~~If discontinuation, decommissioning, or mothballing of any power source and or permanent derating of any generating facility is expected:~~
    - i. ~~Identification of each power source or generating unit involved;~~
    - ii. ~~The costs and spending schedule for each discontinuation, decommissioning, mothballing, or derating; and~~
    - iii. ~~The reasons for each discontinuation, decommissioning, mothballing, or derating;~~
  - f. ~~The capital costs and operating and maintenance costs of all new or refurbished transmission and distribution facilities expected during the 15-year period;~~
  - g. ~~An explanation of the need for and purpose of all expected new or refurbished transmission and distribution facilities, which explanation shall incorporate the load-serving entity's most recent transmission plan filed under A.R.S. § 40-360.02(A) and any relevant provisions of the Commission's most recent Biennial Transmission Assessment decision regarding the adequacy of transmission facilities in Arizona; and~~
  - h. ~~Cost analyses and cost projections;~~

2. — Documentation of the data, assumptions, and methods or models used to forecast production costs and power production for the 15-year resource plan, including the method by which the forecast was benchmarked;
3. — A description of each potential power source that was rejected; the capital costs, operating costs, and maintenance costs of each rejected source; and an explanation of the reasons for rejecting each source;
4. — A 15-year forecast of self-generation by customers of the load-serving entity, in terms of annual peak production (megawatts) and annual energy production (megawatt-hours);
5. — Disaggregation of the forecast of subsection (D)(4) into two components, one reflecting the self-generation projected if no additional efforts are made to self-generation, and one reflecting the self-generation projected to result from the load-serving entity's institution of additional forecasted self-generation measures;
6. — A 15-year forecast of the annual capital costs and operating and maintenance costs of the self-generation identified under subsections (D)(4) and (D)(5);
7. — Documentation of the analysis of the self-generation under subsections (D)(4) through (6);
8. — A plan that considers using a wide range of resources and promotes fuel and technology diversity within its portfolio;
9. — A calculation of the benefits of generation using renewable energy resources;
10. — A plan that factors in the delivered cost of all resource options, including costs associated with environmental compliance, system integration, backup capacity, and transmission delivery;
11. — Analysis of integration costs for intermittent resources;
12. — A plan to increase the efficiency of the load-serving entity's generation using fossil fuel;
13. — Data to support technology choices for supply-side resources;
14. — A description of the demand management programs or measures included in the 15-year resource plan, including for each demand management program or measure:
  - a. — How and when the program or measure will be implemented;
  - b. — The projected participation level by customer class for the program or measure;

- ~~\_\_\_\_\_ c. \_\_\_\_\_ The expected change in peak demand and energy consumption resulting from the program or measure;~~
- ~~\_\_\_\_\_ d. \_\_\_\_\_ The expected reductions in environmental impacts including air emissions, solid waste, and water consumption attributable to the program or measure;~~
- ~~\_\_\_\_\_ e. \_\_\_\_\_ The expected societal benefits, societal costs, and cost effectiveness of the program or measure;~~
- ~~\_\_\_\_\_ f. \_\_\_\_\_ The expected life of the measure; and~~
- ~~\_\_\_\_\_ g. \_\_\_\_\_ The capital costs, operating costs, and maintenance costs of the measure, and the program costs;~~

~~15. \_\_\_\_\_ For each demand management measure that was considered but rejected:~~

- ~~\_\_\_\_\_ a. \_\_\_\_\_ A description of the measure;~~
- ~~\_\_\_\_\_ b. \_\_\_\_\_ The estimated change in peak demand and energy consumption from the measure;~~
- ~~\_\_\_\_\_ c. \_\_\_\_\_ The estimated cost effectiveness of the measure;~~
- ~~\_\_\_\_\_ d. \_\_\_\_\_ The capital costs, operating costs, and maintenance costs of the measure, and the program costs; and~~
- ~~\_\_\_\_\_ e. \_\_\_\_\_ The reasons for rejecting the measure;~~

~~16. \_\_\_\_\_ Analysis of future fuel supplies that are part of the resource plan; and~~

~~17. \_\_\_\_\_ A plan for reducing environmental impacts related to air emissions, solid waste, and other environmental factors, and a plan for reducing water consumption. The costs for compliance with current and projected future environmental regulations shall be included in the analysis of resources required by R14-2-703(D) and (E). A load serving entity or any interested parties may also provide, for the Commission's consideration, analyses and supporting data pertaining to environmental impacts associated with the generation or delivery of electricity, which may include monetized estimates of environmental impacts that are not included as costs for compliance. Values or factors for compliance costs, environmental impacts, or monetization of environmental impacts may be developed and reviewed by the Commission in other proceedings or stakeholder workshops.~~

~~E. \_\_\_\_\_ A load serving entity shall, by April 1 of each even year, file with Docket Control a compilation of the following analyses and plan:~~

1. — ~~Analyses to identify and assess errors, risks, and uncertainties in the following, completed using methods such as sensitivity analysis and probabilistic analysis:~~
    - a. — ~~Demand forecasts;~~
    - b. — ~~The costs of demand management measures and power supply;~~
    - c. — ~~The availability of sources of power;~~
    - d. — ~~The costs of compliance with existing and expected environmental regulations;~~
    - e. — ~~Any analysis by the load-serving entity in anticipation of potential new or enhanced environmental regulations;~~
    - f. — ~~Changes in fuel prices, and availability;~~
    - g. — ~~Construction costs, capital costs, and operating costs; and~~
    - h. — ~~Other factors the load-serving entity wishes to consider.;~~
  2. — ~~A description and analysis of available means for managing the errors, risks, and uncertainties identified and analyzed in subsection (E)(1), such as obtaining additional information, limiting risk exposure, using incentives, creating additional options, incorporating flexibility, and participating in regional generation and transmission projects; and~~
  3. — ~~A plan to manage the errors, risks, and uncertainties identified and analyzed in subsection (E)(1).~~
- F. — ~~A load-serving entity shall, by April 1 of each even year, file with Docket Control a 15-year resource plan that:~~
1. — ~~Selects a portfolio of resources based upon comprehensive consideration of a wide range of supply and demand-side options;~~
  2. — ~~Will result in the load-serving entity's reliably serving the demand for electric energy services;~~
  3. — ~~Will address the adverse environmental impacts of power production;~~
  4. — ~~Will include renewable energy resources so as to meet at least the greater of the Annual Renewable Energy Requirement in R14-2-1804 or the following annual percentages of retail kWh sold by the load-serving entity:~~

<del>Calendar Year</del>	<del>Percentage of Retail kWh sold during calendar Year</del>

2010	2.5%
2011	3.0%
2012	3.5%
2013	4.0%
2014	4.5%
2015	5.0%
2016	6.0%
2017	7.0%
2018	8.0%
2019	9.0%
2020	10.0%
2021	11.0%
2022	12.0%
2023	13.0%
2024	14.0%
after 2024	15.0%

5. ~~Will include distributed generation energy resources so as to meet at least the greater of the Distributed Renewable Energy Requirement in R14-2-1805 or the following annual percentages as applied to the load-serving entity's Annual Renewable Energy Requirement:~~

~~2007 5%~~  
~~2008 10%~~  
~~2009 15%~~  
~~2010 20%~~  
~~2011 25%~~  
~~After 2011 30%~~

6. ~~Will address energy efficiency so as to meet any requirements set in rule by the Commission;~~

7. ~~Will effectively manage the uncertainty and risks associated with costs, environmental impacts, load forecasts, and other factors;~~

8. ~~Will achieve a reasonable long-term total cost, taking into consideration the objectives set forth in subsections (F)(2) (7) and the uncertainty of future costs; and~~
9. ~~Contains all of the following:~~
  - ~~a. A complete description and documentation of the plan, including supply and demand conditions, availability of transmission, costs, and discount rates utilized;~~
  - ~~b. A comprehensive, self-explanatory load and resources table summarizing the plan;~~
  - ~~c. A brief executive summary;~~
  - ~~d. An index to indicate where the responses to each filing requirement of these rules can be found; and~~
  - ~~e. Definitions of the terms used in the plan.~~
- G. ~~A load-serving entity shall, by April 1 of each odd year, file with Docket Control a work plan that includes:~~
  - ~~1. An outline of the contents of the resource plan the load-serving entity is developing to be filed the following year as required under subsection (F);~~
  - ~~2. The load-serving entity's method for assessing potential resources;~~
  - ~~3. The sources of the load-serving entity's current assumptions; and~~
  - ~~4. 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.~~
- H. ~~With its resource plan, a load-serving entity shall include an action plan, based on the results of the resource planning process, that:~~
  - ~~1. Includes a summary of actions to be taken on future resource acquisitions;~~
  - ~~2. Includes details on resource types, resources capacity, and resource timing; and~~
  - ~~3. Covers the three-year period following the Commission's acknowledgment of the resource plan.~~
- I. ~~If a load-serving entity's submission does not contain sufficient information to allow Staff to analyze the submission fully for compliance with this Article, Staff shall request additional information from the load-serving entity, including the data used in the load-serving entity's analyses.~~



- ~~J. — Staff may request that a load-serving entity complete additional analyses to improve specified components of the load-serving entity's submissions.~~
- ~~K. — If a load-serving entity believes that a data-reporting requirement may result in disclosure of confidential business data or confidential electricity infrastructure information, the load-serving entity may submit to Staff a request that the data be submitted to Staff under a confidentiality agreement, which request shall include an explanation justifying the confidential treatment of the data.~~
- ~~L. — Data protected by a confidentiality agreement shall not be submitted to Docket Control and will not be open to public inspection or otherwise made public except upon an order of the Commission entered after written notice to the load-serving entity.~~
- R14-2-704. — Commission review of load-serving entity resource plans**
- ~~A. — By October 1 of each even year, Staff shall file a report that contains its analysis and conclusions regarding its statewide review and assessments of the load-serving entities' filings made under R14-2-703(C), (D), (E), (F), and (H).~~
- ~~B. — By February 1 of each odd year, the Commission shall issue an order acknowledging a load-serving entity's resource plan or issue an order stating the reasons for not acknowledging the resource plan. The Commission shall order an acknowledgment of a load-serving entity's resource plan, with or without amendment, if the Commission determines that the resource plan, as amended if applicable, complies with the requirements of this Article and that the load-serving entity's resource plan is reasonable and in the public interest, based on the information available to the Commission at the time and considering the following factors:~~
- ~~1. — The total cost of electric energy services;~~
  - ~~2. — The degree to which the factors that affect demand, including demand management, have been taken into account;~~
  - ~~3. — The degree to which supply alternatives, such as self-generation, have been taken into account;~~
  - ~~4. — 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;~~
  - ~~5. — The reliability of power supplies, including fuel diversity and non-cost considerations;~~

- ~~6. The reliability of the transmission grid;~~
- ~~7. The degree to which the load-serving entity considered all relevant resources, risks, and uncertainties;~~
- ~~8. The degree to which the load-serving entity's plan for future resources is in the best interest of its customers;~~
- ~~9. The best combination of expected costs and associated risks for the load-serving entity and its customers; and~~
- ~~10. The degree to which the load-serving entity's resource plan allows for coordinated efforts with other load-serving entities.~~

~~C. The Commission may hold a hearing or workshop regarding a load-serving entity's resource plan. If the Commission holds such a hearing or workshop, the Commission may extend the February 1 deadline for the Commission to issue an order regarding acknowledgment under subsection (B).~~

~~D. While no particular future ratemaking treatment is implied by or shall be inferred from the Commission's acknowledgement, the Commission shall consider a load-serving entity's filings made under R14-2-703 when the Commission evaluates the performance of the load-serving entity in subsequent rate cases and other proceedings.~~

~~E. A load-serving entity may seek Commission approval of specific resource planning actions.~~

~~F. A load-serving entity may file an amendment to an acknowledged resource plan if changes in conditions or assumptions necessitate a material change in the load-serving entity's plan before the next resource plan is due to be filed.~~

#### **R14-2-705. Procurement**

~~A. Except as provided in subsection (B), a load-serving entity may use the following procurement methods for the wholesale acquisition of energy, capacity, and physical power hedge transactions:~~

- ~~1. Purchase through a third-party on-line trading system;~~
- ~~2. Purchase from a third-party independent energy broker;~~
- ~~3. Purchase from a non-affiliated entity through auction or an RFP process;~~
- ~~4. Bilateral contract with a non-affiliated entity;~~

5. ~~Bilateral contract with an affiliated entity, provided that non-affiliated entities were provided notice and an opportunity to compete against the affiliated entity's proposal before the transaction was executed; and~~

6. ~~Any other competitive procurement process approved by the Commission.~~

**B.** ~~A load-serving entity shall use an RFP process as its primary acquisition process for the wholesale acquisition of energy and capacity, unless one of the following exceptions applies:~~

1. ~~The load-serving entity is experiencing an emergency;~~

2. ~~The load-serving entity needs to make a short-term acquisition to maintain system reliability;~~

3. ~~The load-serving entity needs to acquire other components of energy procurement, such as fuel, fuel transportation, and transmission projects;~~

4. ~~The load-serving entity's planning horizon is two years or less;~~

5. ~~The transaction presents the load-serving entity a genuine, unanticipated opportunity to acquire a power supply resource at a clear and significant discount, compared to the cost of acquiring new generating facilities, and will provide unique value to the load-serving entity's customers;~~

6. ~~The transaction is necessary for the load-serving entity to satisfy an obligation under the Renewable Energy Standard rules; or~~

7. ~~The transaction is necessary for the load-serving entity's demand-side management or demand response programs.~~

**C.** ~~A load-serving entity shall engage an independent monitor to oversee all RFP processes for procurement of new resources.~~

**R14-2-706. ~~Independent Monitor Selection and Responsibilities~~**

**A.** ~~When a load-serving entity contemplates engaging in an RFP process, the load-serving entity shall consult with Staff regarding the identity of companies or consultants that could serve as independent monitor for the RFP process.~~

**B.** ~~After consulting with Staff, a load-serving entity shall create a vendor list of three to five candidates to serve as independent monitor and shall file the vendor list with Docket Control to allow interested persons time to review and file objections to the vendor list.~~

- ~~C. — An interested person shall file with Docket Control, within 30 days after a vendor list is filed with Docket Control, any objection that the interested person may have to a candidate's inclusion on a vendor list.~~
- ~~D. — Within 60 days after a vendor list is filed with Docket Control, Staff shall issue a notice identifying each candidate on the vendor list that Staff considers to be qualified to serve as independent monitor for the contemplated RFP process. In making its determination, Staff shall consider the experience of the candidates, the professional reputation of the candidates, and any objections filed by interested persons.~~
- ~~E. — A load serving entity that has completed the actions required by subsections (A) and (B) to comply with a particular Commission Decision is deemed to have complied with subsections (A) and (B) and is not required to repeat those actions.~~
- ~~F. — A load serving entity may retain as independent monitor for the contemplated RFP process and for its future RFP processes any of the candidates identified in Staff's notice.~~
- ~~G. — A load serving entity shall file with Docket Control a written notice of its retention of an independent monitor.~~
- ~~H. — A load serving entity is responsible for paying the independent monitor for its services and may charge a reasonable bidder's fee to each bidder in the RFP process to help offset the cost of the independent monitor's services. A load serving entity may request recovery of the cost of the independent monitor's services, to the extent that the cost is not offset by bidder's fees, in a subsequent rate case. The Commission shall use its discretion in determining whether to allow the cost to be recovered through customer rates.~~
- ~~I. — One week prior to the deadline for submitting bids, a load serving entity shall provide the independent monitor a copy of any bid proposal prepared by the load serving entity or entity affiliated with the load serving entity and of any benchmark or reference cost the load serving entity has developed for use in evaluating bids. The independent monitor shall take steps to secure the load serving entity's bid proposal and any benchmark or reference cost so that they are inaccessible to any bidder, the load serving entity, and any entity affiliated with the load serving entity.~~
- ~~J. — Upon Staff's request, the independent monitor shall provide status reports to Staff throughout the RFP process.~~

**TITLE 14. PUBLIC SERVICE CORPORATIONS; CORPORATIONS AND ASSOCIATIONS;  
SECURITIES REGULATION**

**CHAPTER 2. CORPORATION COMMISSION - FIXED UTILITIES**

**~~ARTICLE 18. RENEWABLE ENERGY STANDARD AND TARIFF~~**

Section

- ~~R14-2-1801. Definitions~~
- ~~R14-2-1802. Eligible Renewable Energy Resources~~
- ~~R14-2-1803. Renewable Energy Credits~~
- ~~R14-2-1804. Annual Renewable Energy Requirement~~
- ~~R14-2-1805. Distributed Renewable Energy Requirement~~
- ~~R14-2-1806. Extra Credit Multipliers~~
- ~~R14-2-1807. Manufacturing Partial Credit~~
- ~~R14-2-1808. Tariff~~
- ~~R14-2-1809. Customer Self-Directed Renewable Energy Option~~
- ~~R14-2-1810. Uniform Credit Purchase Program~~
- ~~R14-2-1811. Net Metering and Interconnection Standards~~
- ~~R14-2-1812. Compliance Reports~~
- ~~R14-2-1813. Implementation Plans~~
- ~~R14-2-1814. Electric Power Cooperatives~~
- ~~R14-2-1815. Enforcement and Penalties~~
- ~~R14-2-1816. Waiver from the Provisions of this Article~~

**~~ARTICLE 18. RENEWABLE ENERGY STANDARD AND TARIFF~~**

**~~R14-2-1801. Definitions~~**

- ~~A. "Affected Utility" means a public service corporation serving retail electric load in Arizona, but excluding any Utility Distribution Company with more than half of its customers located outside of Arizona.~~
- ~~B. "Annual Renewable Energy Requirement" means the portion of an Affected Utility's annual retail electricity sales that must come from Eligible Renewable Energy Resources.~~

- ~~C. “Conventional Energy Resource” means an energy resource that is non-renewable in nature, such as natural gas, coal, oil, and uranium, or electricity that is produced with energy resources that are not Renewable Energy Resources.~~
- ~~D. “Customer Self Directed Renewable Energy Option” means a Commission approved program under which an Eligible Customer may self-direct the use of its allocation of funds collected pursuant to an Affected Utility’s Tariff.~~
- ~~E. “Distributed Generation” means electric generation sited at a customer premises, providing electric energy to the customer load on that site or providing wholesale capacity and energy to the local Utility Distribution Company for use by multiple customers in contiguous distribution substation service areas. The generator size and transmission needs shall be such that the plant or associated transmission lines do not require a Certificate of Environmental Compatibility from the Corporation Commission.~~
- ~~F. “Distributed Renewable Energy Requirement” means a portion of the Annual Renewable Energy Requirement that must be met with Renewable Energy Credits derived from resources that qualify as Distributed Renewable Energy Resources pursuant to R14-2-1802(B).~~
- ~~G. “Distributed Solar Electric Generator” means electric generation sited at a customer premises, providing electric energy from solar electric resources to the customer load on that site or providing wholesale capacity and energy to the local Utility Distribution Company for use by multiple customers in contiguous distribution substation service areas. The generator size and transmission needs shall be such that the plant or associated transmission lines do not require a Certificate of Environmental Compatibility from the Corporation Commission.~~
- ~~H. “Eligible Customer” means an entity that pays Tariff funds of at least \$25,000 annually for any number of related accounts or services within an Affected Utility’s service area.~~
- ~~I. “Extra Credit Multiplier” means a way to increase the Renewable Energy Credits attributable to specific Eligible Renewable Energy Resources in order to encourage specific renewable applications.~~
- ~~J. “Green Pricing” means a rate option in which a customer elects to pay a tariffed rate premium for electricity derived from Eligible Renewable Energy Resources.~~
- ~~K. “Market Cost of Comparable Conventional Generation” means the Affected Utility’s energy and capacity cost of producing or procuring the incremental electricity that would be avoided by the resources used to meet the Annual Renewable Energy Requirement, taking into account hourly,~~



~~seasonal, and long-term supply and demand circumstances. Avoided costs include any avoided transmission and distribution costs and any avoided environmental compliance costs.~~

~~L. "Net Billing" means a system of billing a customer who installs an Eligible Renewable Energy Resource generator on the customer's premises for retail electricity purchased at retail rates while crediting the customer's bill for any customer generated electricity sold to the Affected Utility at avoided cost.~~

~~M. "Net Metering" means a system of metering electricity by which the Affected Utility credits the customer at the full retail rate for each kilowatt-hour of electricity produced by an Eligible Renewable Energy Resource system installed on the customer generator's side of the electric meter, up to the total amount of electricity used by that customer during an annualized period, and which compensates the customer-generator at the end of the annualized period for any excess credits at a rate equal to the Affected Utility's avoided cost of wholesale power. The Affected Utility does not charge the customer-generator any additional fees or charges or impose any equipment or other requirements unless the same is imposed on customers in the same rate class that the customer-generator would qualify for if the customer-generator did not have generation equipment.~~

~~N. "Renewable Energy Credit" means the unit created to track kWh derived from an Eligible Renewable Energy Resource or kWh equivalent of Conventional Energy Resources displaced by Distributed Renewable Energy Resources.~~

~~O. "Renewable Energy Resource" means an energy resource that is replaced rapidly by a natural, ongoing process and that is not nuclear or fossil fuel.~~

~~P. "Tariff" means a Commission-approved rate designed to recover an Affected Utility's reasonable and prudent costs of complying with these rules.~~

~~Q. "Utility Distribution Company" means a public service corporation that operates, constructs, or maintains a distribution system for the delivery of power to retail customers.~~

~~R. "Wholesale Distributed Generation Component" means non-utility owners of Eligible Renewable Energy Resources that are located within the distribution system and that do not require a transmission line over 69 kv to deliver power at wholesale to an Affected Utility to meet its Annual Renewable Energy Requirements.~~

#### **R14-2-1802. Eligible Renewable Energy Resources**

A. ~~“Eligible Renewable Energy Resources” are applications of the following defined technologies that displace Conventional Energy Resources that would otherwise be used to provide electricity to an Affected Utility’s Arizona customers:~~

- ~~1. “Biogas Electricity Generator” is a generator that produces electricity from gases that are derived from plant derived organic matter, agricultural food and feed matter, wood wastes, aquatic plants, animal wastes, vegetative wastes, or wastewater treatment facilities using anaerobic digestion or from municipal solid waste through a digester process, an oxidation process, or other gasification process.~~
- ~~2. “Biomass Electricity Generator” is an electricity generator that uses any raw or processed plant-derived organic matter available on a renewable basis, including: dedicated energy crops and trees; agricultural food and feed crops; agricultural crop wastes and residues; wood wastes and residues, including landscape waste, right-of-way tree trimmings, or small diameter forest thinnings that are 12” in diameter or less; dead and downed forest products; aquatic plants; animal wastes; other vegetative waste materials; non-hazardous plant matter waste material that is segregated from other waste; forest related resources, such as harvesting and mill residue, pre-commercial thinnings, slash, and brush; miscellaneous waste, such as waste pellets, crates, and dunnage; and recycled paper fibers that are no longer suitable for recycled paper production, but not including painted, treated, or pressurized wood, wood contaminated with plastics or metals, tires, or recyclable post-consumer waste paper.~~
- ~~3. “Distributed Renewable Energy Resources” as defined in subsection (B).~~
- ~~4. “Eligible Hydropower Facilities” are hydropower generators that were in existence prior to 1997 and that satisfy one of the following two criteria:~~
  - ~~a. New Increased Capacity of Existing Hydropower Facilities: A hydropower facility that increases capacity due to improved technological or operational efficiencies or operational improvements resulting from improved or modified turbine design, improved or modified wicket gate assembly design, improved hydrological flow conditions, improved generator windings, improved electrical excitation systems, increases in transformation capacity, and improved system control and operating limit modifications. The electricity kWh that are eligible to meet the Annual Renewable Energy Requirements shall be limited to the new,~~

~~incremental kWh output resulting from the capacity increase that is delivered to Arizona customers to meet the Annual Renewable Energy Requirement.~~

~~b. Generation from pre-1997 hydropower facilities that is used to firm or regulate the output of other eligible, intermittent renewable resources. The electricity kWh that are eligible to meet the Annual Renewable Energy Requirements shall be limited to the kWh actually generated to firm or regulate the output of eligible intermittent Renewable Energy Resources and that are delivered to Arizona customers to meet the Annual Renewable Energy Requirements.~~

~~5. "Fuel Cells that Use Only Renewable Fuels" are fuel cell electricity generators that operate on renewable fuels, such as hydrogen created from water by Eligible Renewable Energy Resources. Hydrogen created from non-Renewable Energy Resources, such as natural gas or petroleum products, is not a renewable fuel.~~

~~6. "Geothermal Generator" is an electricity generator that uses heat from within the earth's surface to produce electricity.~~

~~7. "Hybrid Wind and Solar Electric Generator" is a system in which a Wind Generator and a solar electric generator are combined to provide electricity.~~

~~8. "Landfill Gas Generator" is an electricity generator that uses methane gas obtained from landfills to produce electricity.~~

~~9. "New Hydropower Generator of 10 MW or Less" is a generator, installed after January 1, 2006, that produces 10 MW or less and is either:~~

~~a. A low-head, micro hydro run-of-the-river system that does not require any new damming of the flow of the stream; or~~

~~b. An existing dam that adds power generation equipment without requiring a new dam, diversion structures, or a change in water flow that will adversely impact fish, wildlife, or water quality; or~~

~~c. Generation using canals or other irrigation systems.~~  
~~10. "Solar Electricity Resources" use sunlight to produce electricity by either photovoltaic devices or solar thermal electric resources.~~

~~11. "Wind Generator" is a mechanical device that is driven by wind to produce electricity.~~

~~B. "Distributed Renewable Energy Resources" are applications of the following defined technologies that are located at a customer's premises and that displace Conventional Energy Resources that would otherwise be used to provide electricity to Arizona customers:~~

- ~~1. "Biogas Electricity Generator," "Biomass Electricity Generator," "Geothermal Generator," "Fuel Cells that Use Only Renewable Fuels," "New Hydropower Generator of 10 MW or Less," or "Solar Electricity Resources," as each of those terms is defined in subsections (A)(1), (A)(2), (A)(5), (A)(6), (A)(9), and (A)(10).~~
- ~~2. "Biomass Thermal Systems" and "Biogas Thermal Systems" are systems which use fuels as defined in subsections (A)(1) and (A)(2) to produce thermal energy and that comply with Environmental Protection Agency Certification Programs or are permitted by state, county, or local air quality authorities. For purposes of this definition "Biomass Thermal Systems" and "Biogas Thermal Systems" do not include biomass and wood stoves, furnaces, and fireplaces.~~
- ~~3. "Commercial Solar Pool Heaters" are devices that use solar energy to heat commercial or municipal swimming pools.~~
- ~~4. "Geothermal Space Heating and Process Heating Systems" are systems that use heat from within the earth's surface for space heating or for process heating.~~~~5. "Renewable Combined Heat and Power System" is a Distributed Generation system, fueled by an Eligible Renewable Energy Resource, that produces both electricity and useful renewable process heat. Both the electricity and renewable process heat may be used to meet the Distributed Renewable Energy Requirement.~~
- ~~6. "Solar Daylighting" is the non-residential application of a device specifically designed to capture and redirect the visible portion of the solar beam, while controlling the infrared portion, for use in illuminating interior building spaces in lieu of artificial lighting.~~
- ~~7. "Solar Heating, Ventilation, and Air Conditioning" ("HVAC") is the combination of Solar Space Cooling and Solar Space Heating as part of one system.~~
- ~~8. "Solar Industrial Process Heating and Cooling" is the use of solar thermal energy for industrial or commercial manufacturing or processing applications.~~
- ~~9. "Solar Space Cooling" is a technology that uses solar thermal energy absent the generation of electricity to drive a refrigeration machine that provides for space cooling in a building.~~
- ~~10. "Solar Space Heating" is a method whereby a mechanical system is used to collect solar energy to provide space heating for buildings.~~

11. ~~“Solar Water Heater” is a device that uses solar energy rather than electricity or fossil fuel to heat water for residential, commercial, or industrial purposes.~~

12. ~~“Wind Generator of 1 MW or Less” is a mechanical device, with an output of 1 MW or less, that is driven by wind to produce electricity.~~

~~C. Except as provided in subsection (A)(4), Eligible Renewable Energy Resources shall not include facilities installed before January 1, 1997.~~

~~D. The Commission may adopt pilot programs in which additional technologies are established as Eligible Renewable Energy Resources. Any such additional technologies shall be Renewable Energy Resources that produce electricity, replace electricity generated by Conventional Energy Resources, or replace the use of fossil fuels with Renewable Energy Resources. Energy conservation products, energy management products, energy efficiency products, or products that use non-renewable fuels shall not be eligible for these pilot programs.~~

**~~R14-2-1803. Renewable Energy Credits~~**

~~A. One Renewable Energy Credit shall be created for each kWh derived from an Eligible Renewable Energy Resource.~~

~~B. For Distributed Renewable Energy Resources, one Renewable Energy Credit shall be created for each 3,415 British Thermal Units of heat produced by a Solar Water Heating System, a Solar Industrial Process Heating and Cooling System, Solar Space Cooling System, Biomass Thermal System, Biogas Thermal System, or a Solar Space Heating System.~~

~~C. An Affected Utility may transfer Renewable Energy Credits to another party and may acquire Renewable Energy Credits from another party. A Renewable Energy Credit is owned by the owner of the Eligible Renewable Energy Resource from which it was derived unless specifically transferred.~~

~~D. All transfers of Renewable Energy Credits shall be appropriately documented to demonstrate that the energy associated with the Renewable Energy Credits meets the provisions of R14-2-1802.~~

~~E. Any contract by an Affected Utility for purchase or sale of energy or Renewable Energy Credits to meet the requirements of this Rule shall explicitly describe the transfer of rights concerning both energy and Renewable Energy Credits.~~

~~F. Except in the case of Distributed Renewable Energy Resources, Affected Utilities must demonstrate the delivery of energy from Eligible Renewable Energy Resources to their retail consumers such as by providing proof that the necessary transmission rights were reserved and utilized to deliver energy~~

~~from Eligible Renewable Energy Resources to the Affected Utility's system, if transmission is required, or that the appropriate control area operators scheduled the energy from Eligible Renewable Energy Resources for delivery to the Affected Utility's system.~~

**~~R14-2-1804. Annual Renewable Energy Requirement~~**

~~A. In order to ensure reliable electric service at reasonable rates, each Affected Utility shall be required to satisfy an Annual Renewable Energy Requirement by obtaining Renewable Energy Credits from Eligible Renewable Energy Resources.~~

~~B. An Affected Utility's Annual Renewable Energy Requirement shall be calculated each calendar year by applying the following applicable annual percentage to the retail kWh sold by the Affected Utility during that calendar year:~~

<del>2006</del>	<del>1.25%</del>
<del>2007</del>	<del>1.50%</del>
<del>2008</del>	<del>1.75%</del>
<del>2009</del>	<del>2.00%</del>
<del>2010</del>	<del>2.50%</del>
<del>2011</del>	<del>3.00%</del>
<del>2012</del>	<del>3.50%</del>
<del>2013</del>	<del>4.00%</del>
<del>2014</del>	<del>4.50%</del>
<del>2015</del>	<del>5.00%</del>
<del>2016</del>	<del>6.00%</del>
<del>2017</del>	<del>7.00%</del>
<del>2018</del>	<del>8.00%</del>
<del>2019</del>	<del>9.00%</del>
<del>2020</del>	<del>10.00%</del>
<del>2021</del>	<del>11.00%</del>
<del>2022</del>	<del>12.00%</del>
<del>2023</del>	<del>13.00%</del>
<del>2024</del>	<del>14.00%</del>
<del>After 2024</del>	<del>15.00%</del>



~~—The annual increase in the annual percentage for each Affected Utility will be pro-rated for the first year based on when the Affected Utility's funding mechanism is approved.~~

~~C. An Affected Utility may use Renewable Energy Credits acquired in any year to meet its Annual Renewable Energy Requirement.~~

~~D. Once a Renewable Energy Credit is used by any Affected Utility to satisfy these requirements, the credit is retired and cannot be subsequently used to satisfy these rules or any other regulatory requirement.~~

~~E. If an Affected Utility trades or sells environmental pollution reduction credits or any other environmental attributes associated with kWh produced by an Eligible Renewable Energy Resource, the Affected Utility may not apply Renewable Energy Credits derived from that same kWh to satisfy the requirements of these rules.~~

~~F. No more than 20 percent of an Affected Utility's Annual Renewable Energy Requirement may be met with Renewable Energy Credits derived pursuant to R14-2-1807.~~

~~G. An Affected Utility may ask the Commission to preapprove agreements to purchase energy or Renewable Energy Credits from Eligible Renewable Energy Resources.~~

**R14-2-1805. Distributed Renewable Energy Requirement**

~~A. In order to improve system reliability, each Affected Utility shall be required to satisfy a Distributed Renewable Energy Requirement by obtaining Renewable Energy Credits from Distributed Renewable Energy Resources.~~

~~B. An Affected Utility's Distributed Renewable Energy Requirement shall be calculated each calendar year by applying the following applicable annual percentage to the Affected Utility's Annual Renewable Energy Requirement:~~

<del>2007</del>	<del>5%</del>
<del>2008</del>	<del>10%</del>
<del>2009</del>	<del>15%</del>
<del>2010</del>	<del>20%</del>
<del>2011</del>	<del>25%</del>
<del>After 2011</del>	<del>30%</del>

~~—The annual increase in the annual percentage for each Affected Utility will be pro-rated for the first year based on when the Affected Utility's funding mechanism is approved.~~

- ~~C. An Affected Utility may use Renewable Energy Credits acquired in any year to meet its Distributed Renewable Energy Requirement. Once a Renewable Energy Credit is used by any Affected Utility to satisfy these requirements, the credit is retired.~~
- ~~D. An Affected Utility shall meet one-half of its annual Distributed Renewable Energy Requirement from residential applications and the remaining one-half from non-residential, non-utility applications.~~
- ~~E. An Affected Utility may satisfy no more than 10 percent of its annual Distributed Renewable Energy Requirement from Renewable Energy Credits derived from distributed Renewable Energy Resources that are non-utility owned generators that sell electricity at wholesale to Affected Utilities. This Wholesale Distributed Generation Component shall qualify for the non-residential portion of the Distributed Renewable Energy Requirement.~~

**~~R14-2-1806, Extra Credit Multipliers~~**

- ~~A. Renewable Energy Credits derived from Eligible Renewable Energy Resources installed after December 31, 2005, shall not be eligible for Extra Credit Multipliers.~~
- ~~B. The extra Renewable Energy Credits resulting from any applicable multiplier shall be added to the Renewable Energy Credits produced by the Eligible Renewable Energy Resource to determine the total Renewable Energy Credits that may be used to meet an Affected Utility's Annual Renewable Energy Requirement.~~
- ~~C. "Early Installation Extra Credit Multiplier." Affected Utilities acquiring Renewable Energy Credits from a Solar Electricity Resource, a Solar Water Heater, a Solar Space Cooling system, a Landfill Gas Generator, a Wind Generator, or a Biomass Electricity Generator that was installed and began operations between January 1, 2001, and December 31, 2003, shall be eligible for an Early Installation Extra Credit Multiplier. Renewable Energy Credits derived from such facilities and acquired by Affected Utilities shall be eligible for five years following the facility's operational start up. The multiplier shall vary according to the year in which the system began operating:~~
- |                 |                  |               |
|-----------------|------------------|---------------|
| <del>2001</del> | <del>_____</del> | <del>.3</del> |
| <del>2002</del> | <del>_____</del> | <del>.2</del> |
| <del>2003</del> | <del>_____</del> | <del>.1</del> |
- ~~D. "In-State Power Plant Installation Extra Credit Multiplier." Affected Utilities acquiring Renewable Energy Credits from a Solar Electricity Resource that was installed in Arizona on or before December~~

~~31, 2005, shall be eligible for an In-State Power Plant Installation Extra Credit Multiplier. The Renewable Energy Credits derived from such a facility and acquired by an Affected Utility shall be multiplied by .5 annually for the life of the facility. The extra Renewable Energy Credits resulting from the multiplier shall be added to the Renewable Energy Credits produced by the Eligible Renewable Energy Resource to determine the total Renewable Energy Credits that may be used to meet an Affected Utility's Annual Renewable Energy Requirement.~~

~~E. "In-State Manufacturing and Installation Content Extra Credit Multiplier." Affected Utilities acquiring Renewable Energy Credits from a Solar Electricity Resource, a Solar Water Heater, a Solar Space Cooling system, a Landfill Gas Generator, a Wind Generator, or a Biomass Electricity Generator that was installed in Arizona on or before December 31, 2005, and that contains components manufactured in Arizona shall be eligible for an In-State Manufacturing and Installation Content Extra Credit Multiplier. The Renewable Energy Credits derived from such a facility and acquired by an Affected Utility shall be multiplied annually for the life of the facility by a factor determined by multiplying .5 times the percent of Arizona content of the total installed plant.~~

~~F. "Distributed Solar Electric Generator and Solar Incentive Program Extra Credit Multiplier." Affected Utilities acquiring Renewable Energy Credits from a Distributed Solar Electric Generator that was installed in Arizona on or before December 31, 2005, shall be eligible for a Distributed Solar Electric Generator and Solar Incentive Program Extra Credit Multiplier if the facility meets at least two of the following criteria:~~

- ~~1. The facility is installed on customer premises;~~
- ~~2. The facility is included in any Affected Utility's approved Green Pricing program;~~
- ~~3. The facility is included in any Affected Utility's approved Net Metering or Net Billing program;~~
- ~~4. The facility is included in any Affected Utility's approved solar leasing program, or~~
- ~~5. The facility is owned by and located on an Affected Utility's property or customer property. The Renewable Energy Credits derived from such a facility and acquired by an Affected Utility shall be multiplied by .5 annually for the life of the facility. Meters will be attached to each solar electric generator and read at least once annually to verify solar performance.~~

~~G. All multipliers are additive, except that the maximum combined Extra Credit Multiplier shall not exceed 2.0.~~

**~~R14-2-1807. Manufacturing Partial Credit~~**

- ~~A. An Affected Utility may acquire Renewable Energy Credits to apply to the non-distributed portion of its Annual Renewable Energy Requirement if it or its affiliate owns or makes a significant investment in any solar electric manufacturing plant located in Arizona or if it or its affiliate provides incentives to a manufacturer of solar electric products to locate a manufacturing facility in Arizona.~~
- ~~B. The Renewable Energy Credits shall be equal to the nameplate capacity of the solar electric generators produced and sold in a calendar year times 2,190 hours, which approximates a 25 percent capacity factor.~~
- ~~C. Extra credit multipliers shall not apply to Renewable Energy Credits created by this Section.~~

**~~R14-2-1808. Tariff~~**

- ~~A. Within 60 days of the effective date of these rules, each Affected Utility shall file with the Commission a Tariff in substantially the same form as the Sample Tariff set forth in these rules that proposes methods for recovering the reasonable and prudent costs of complying with these rules. The specific amounts in the Sample Tariff are for illustrative purposes only and Affected Utilities may submit, with proper support, Tariff filings with alternative surcharge amounts.~~
- ~~B. The Affected Utility's Tariff filing shall provide the following information:~~
- ~~1. Financial information and supporting data sufficient to allow the Commission to determine the Affected Utility's fair value for purposes of evaluating the Affected Utility's proposed Tariff. Information submitted in the format of the Annual Report required under R14-2-212(G)(4) will be the minimum information necessary for filing a Tariff application but Commission Staff may request additional information depending upon the type of Tariff filing that is submitted.~~
  - ~~2. A discussion of the suitability of the Sample Tariff set forth in Appendix A for recovering the Affected Utility's reasonable and prudent costs of complying with these rules,~~
  - ~~3. Data to support the level of costs that the Affected Utility contends will be incurred in order to comply with these rules,~~
  - ~~4. Data to demonstrate that the Affected Utility's proposed Tariff is designed to recover only the costs in excess of the Market Cost of Comparable Conventional Generation, and~~
  - ~~5. Any other information that the Commission believes will be relevant to the Commission's consideration of the Tariff filing.~~

- ~~C. The Commission will approve, modify, or deny a Tariff proposed pursuant to subsection (A) within 180 days after the Tariff has been filed. The Commission may suspend this deadline or adopt an alternative procedural schedule for good cause. The Affected Utility's Annual Renewable Energy Requirement, as set forth in R14-2-1804(B), Distributed Renewable Energy Requirement, as set forth in R14-2-1805(B), will be effective upon Commission approval of the Tariff filed pursuant to this Section.~~
- ~~D. If an Affected Utility has an adjustor mechanism for the recovery of costs related to Annual Renewable Energy Requirements, the Affected Utility may file a request to reset its adjustor mechanism in lieu of a Tariff pursuant to subsection (A). The Affected Utility's filing shall provide all the information required by subsection (B), except that it may omit information specifically related to the fair value determination. The Affected Utility's Annual Renewable Energy Requirement, as set forth in R14-2-1804(B), and Distributed Renewable Energy Requirement, as set forth in R14-2-1805(B) will be effective upon Commission approval of the adjustor mechanism rate filed pursuant to this Section.~~
- ~~E. An Affected Utility may file a rate case pursuant to R14-2-103 in lieu of a Tariff pursuant to subsection (A). The Affected Utility's filing shall provide all information required by subsection (B).~~

**R14-2-1809. Customer Self-Directed Renewable Energy Option**

- ~~A. By January 1, 2007, each Affected Utility shall file with Docket Control a Tariff by which an Eligible Customer may apply to an Affected Utility to receive funds to install distributed Renewable Energy Resources. The funds annually received by an Eligible Customer pursuant to this Tariff may not exceed the amount annually paid by the Eligible Customer pursuant to the Affected Utility's Tariff.~~
- ~~B. An Eligible Customer seeking to participate in this program shall submit to the Affected Utility a written application that describes the Renewable Energy Resources that it proposes to install and the projected cost of the project. An Eligible Customer shall provide at least half of the funding necessary to complete the project described in its application.~~
- ~~C. All Renewable Energy Credits derived from the project, including generation and Extra Credit Multipliers, shall be applied to satisfy the Affected Utility's Annual Renewable Energy Requirement.~~

**R14-2-1810. Uniform Credit Purchase Program**

- ~~A. The Director of the Utilities Division shall establish a Uniform Credit Purchase Program working group, which will study issues related to implementing Distributed Renewable Energy Resources. The~~



~~working group shall address the consumer participation process, budgets, incentive levels, eligible technologies, system requirements, installation requirements, and any other issues that are relevant to encouraging the implementation of Distributed Renewable Energy Resources. No later than March 1, 2007, the Director of the Utilities Division shall file a staff report with recommendations for Uniform Credit Purchase Programs.~~

~~B. No later than July 1, 2007, each Affected Utility shall file a Uniform Credit Purchase Program for Commission review and approval.~~

**~~R14-2-1811. Net Metering and Interconnection Standards~~**

~~The Commission Staff shall host a series of workshops addressing the issues of rate design including Net Metering and interconnection standards. Upon completion of this task, and the adoption of rules or standards, if appropriate, each Affected Utility shall file conforming Net Metering tariffs and interconnection standards in Docket Control.~~

**~~R14-2-1812. Compliance Reports~~**

~~A. Beginning April 1, 2007, and every April 1st thereafter, each Affected Utility shall file with Docket Control a report that describes its compliance with the requirements of these rules for the previous calendar year. The Affected Utility shall also transmit to the Director of the Utilities Division an electronic copy of this report that is suitable for posting on the Commission's website.~~

~~B. The compliance report shall include the following information:~~

- ~~1. The actual kWh of energy or equivalent obtained from Eligible Renewable Energy Resources;~~
- ~~2. The kWh of energy or equivalent obtained from Eligible Renewable Energy Resources normalized to reflect a full year's production;~~
- ~~3. The kW of generation capacity, disaggregated by technology type;~~
- ~~4. Cost information regarding cents per actual kWh of energy obtained from Eligible Renewable Energy Resources and cents per kW of generation capacity, disaggregated by technology type;~~
- ~~5. A breakdown of the Renewable Energy Credits used to satisfy both the Annual Renewable Energy Requirement and the Distributed Renewable Energy Requirement and appropriate documentation of the Affected Utility's receipt of those Renewable Energy Credits; and~~



~~6. A description of the Affected Utility's procedures for choosing Eligible Renewable Energy Resources and a certification from an independent auditor that those procedures are fair and unbiased and have been appropriately applied.~~

~~C. The Commission may hold a hearing to determine whether an Affected Utility's compliance report satisfies the requirements of these rules.~~

#### **~~R14-2-1813. Implementation Plans~~**

~~A. Beginning July 1, 2007, and every July 1st thereafter, each Affected Utility shall file with Docket Control for Commission review and approval a plan that describes how it intends to comply with these rules for the next calendar year. The Affected Utility shall also transmit an electronic copy of this plan that is suitable for posting on the Commission's website to the Director of the Utilities Division.~~

~~B. The implementation plan shall include the following information:~~

- ~~1. A description of the Eligible Renewable Energy Resources, identified by technology, proposed to be added by year for the next five years and a description of the kW and kWh to be obtained from each of those resources;~~
- ~~2. The estimated cost of each Eligible Renewable Energy Resource proposed to be added, including cost per kWh and total cost per year;~~
- ~~3. A description of the method by which each Eligible Renewable Energy Resource is to be obtained, such as self-build, customer installation, or request for proposals;~~
- ~~4. A proposal that evaluates whether the Affected Utility's existing rates allow for the ongoing recovery of the reasonable and prudent costs of complying with these rules, including a Tariff application that meets the requirements of R14-2-1808 and addresses the Sample Tariff set forth in Appendix A if necessary; and~~
- ~~5. A line item budget that allocates specific funding for Distributed Renewable Energy Resources, for the Customer Self-Directed Renewable Energy Option, for power purchase agreements, for utility-owned systems, and for each Eligible Renewable Energy Resource described in the Affected Utility's implementation plan~~

~~C. The Commission may hold a hearing to determine whether an Affected Utility's implementation plan satisfies the requirements of these rules.~~

#### **~~R14-2-1814. Electric Power Cooperatives~~**

- ~~A. Within 60 days of the effective date of these rules, every electric cooperative that is an Affected Utility shall file with Docket Control an appropriate plan for acquiring Renewable Energy Credits from Eligible Renewable Energy Resources for the next calendar year and a Tariff that proposes methods for recovering the reasonable and prudent costs of complying with its proposed plan and addresses the Sample Tariff set forth in Appendix A. The cooperative shall also transmit electronic copies of these filings that are suitable for posting on the Commission's website to the Director of the Utilities Division. Upon Commission approval of this plan, its provisions shall substitute for the requirements of R14-2-1804 and R14-2-1805 for the electric power cooperative proposing the plan.~~
- ~~B. Beginning July 1, 2007, and every July 1st thereafter, every electric cooperative that is an Affected Utility shall file with Docket Control an appropriate plan for acquiring Renewable Energy Credits from Eligible Renewable Energy Resources for the next calendar year. The cooperative shall also transmit an electronic copy of this plan that is suitable for posting on the Commission's website to the Director of the Utilities Division.~~

**R14-2-1815. Enforcement and Penalties**

- ~~A. If an Affected Utility fails to meet the annual requirements set forth in R14-2-1804 and R14-2-1805, it shall include with its annual compliance report a notice of noncompliance.~~
- ~~B. The notice of noncompliance shall provide the following information:~~
- ~~1. A computation of the difference between the Renewable Energy Credits required by R14-2-1804 and R14-2-1805 and the amount actually obtained.~~
  - ~~2. A plan describing how the Affected Utility intends to meet the shortfall from the previous calendar year in the current calendar year, and~~
  - ~~3. An estimate of the costs of meeting the shortfall.~~
- ~~C. If the Commission finds after affording an Affected Utility notice and an opportunity to be heard that the Affected Utility has failed to comply with its implementation plan approved by the Commission as set forth in R14-2-1813, the Commission may find that the Affected Utility shall not recover the costs of meeting the shortfall described in R14-2-1815(B) in rates.~~
- ~~D. Nothing herein is intended to limit the actions the Commission may take or the penalties the Commission may impose pursuant to Arizona Revised Statutes, Chapter 2, Article 9. An Affected~~

~~Utility is entitled to notice and an opportunity to be heard prior to Commission action or imposition of penalties.~~

**~~R14-2-1816. Waiver from the Provisions of this Article~~**

~~The Commission may waive compliance with any provision of this Article for good cause. Any Affected Utility may petition the Commission to waive its compliance with any provision of this Article for good cause. A petition filed pursuant to these rules shall have priority over other matters filed at the Commission.~~

**~~Appendix A. Sample Tariff~~**

~~Unless otherwise ordered by the Commission, the renewable energy standard surcharge shall be assessed monthly to every retail electric service. This monthly assessment will be the lesser of \$0.004988 per kWh or:~~

- ~~1. For residential customers, \$1.05 per service;~~
- ~~2. For non-residential customers, \$39.00 per service;~~
- ~~3. For non-residential customers whose metered demand is 3,000 kW or more for three consecutive months, \$117.00 per service;~~
- ~~4. For non-metered services, the lesser of the load profile or otherwise estimated kWh required to provide the service in question, or the service's contract kWh shall be used in the calculation of the surcharge.~~

**TITLE 14. PUBLIC SERVICE CORPORATIONS; CORPORATIONS AND ASSOCIATIONS;  
SECURITIES REGULATION**

**CHAPTER 2. CORPORATION COMMISSION**

**FIXED UTILITIES**

**ARTICLE 24. ELECTRIC UTILITY ENERGY EFFICIENCY STANDARDS**

**~~R14-2-2401. Definitions~~**

~~In this Article, unless otherwise specified:~~

- ~~1. "Adjustment mechanism" means a Commission-approved provision in an affected utility's rate schedule allowing the affected utility to increase and decrease a certain rate or rates, in an established manner, when increases and decreases in specific costs are incurred by the affected utility.~~
- ~~2. "Affected utility" means a public service corporation that provides electric service to retail customers in Arizona.~~
- ~~3. "Baseline" means the level of electricity demand, electricity consumption, and associated expenses estimated to occur in the absence of a specific DSM program, determined as provided in R14-2-2413.~~
- ~~4. "CHP" means combined heat and power, which is using a primary energy source to simultaneously produce electrical energy and useful process heat.~~
- ~~5. "Commission" means the Arizona Corporation Commission.~~
- ~~6. "Cost-effective" means that total incremental benefits from a DSM measure or DSM program exceed total incremental costs over the life of the DSM measure, as determined under R14-2-2412.~~
- ~~7. "Customer" means the person or entity in whose name service is rendered to a single contiguous field, location, or facility, regardless of the number of meters at the field, location, or facility.~~
- ~~8. "Delivery system" means the infrastructure through which an affected utility transmits and then distributes electrical energy to its customers.~~
- ~~9. "Demand savings" means the load reduction, measured in kW, occurring during a relevant peak period or periods as a direct result of energy efficiency and demand response programs.~~
- ~~10. "Demand response" means modification of customers' electricity consumption patterns, affecting the timing or quantity of customer demand and usage, achieved through intentional actions taken by an affected utility or customer because of changes in prices, market conditions, or threats to system reliability.~~

11. ~~“Distributed generation” means the production of electricity on the customer’s side of the meter, for use by the customer, through a process such as CHP.~~
12. ~~“DSM” means demand side management, the implementation and maintenance of one or more DSM programs.~~
13. ~~“DSM measure” means any material, device, technology, educational program, pricing option, practice, or facility alteration designed to result in reduced peak demand, increased energy efficiency, or shifting of electricity consumption to off peak periods and includes CHP used to displace space heating, water heating, or another load.~~
14. ~~“DSM program” means one or more DSM measures provided as part of a single offering to customers.~~
15. ~~“DSM tariff” means a Commission approved schedule of rates designed to recover an affected utility’s reasonable and prudent costs of complying with this Article.~~
16. ~~“Electric utility” means a public service corporation providing electric service to the public.~~
17. ~~“Energy efficiency” means the production or delivery of an equivalent level and quality of end-use electric service using less energy, or the conservation of energy by end-use customers.~~
18. ~~“Energy efficiency standard” means the reduction in retail energy sales, in percentage of kWh, required to be achieved through an affected utility’s approved DSM programs as prescribed in R14-2-2404.~~
19. ~~“Energy savings” means the reduction in a customer’s energy consumption directly resulting from a DSM program, expressed in kWh.~~
20. ~~“Energy service company” means a company that provides a broad range of services related to energy efficiency, including energy audits, the design and implementation of energy efficiency projects, and the installation and maintenance of energy efficiency measures.~~
21. ~~“Environmental benefits” means avoidance of costs for compliance, or reduction in environmental impacts, for things such as, but not limited to:~~
  - a. ~~Water use and water contamination,~~
  - b. ~~Monitoring storage and disposal of solid waste such as coal ash (bottom and fly),~~
  - c. ~~Health effects from burning fossil fuels, and~~
  - d. ~~Emissions from transportation and production of fuels and electricity.~~
22. ~~“Fuel neutral” means without promoting or otherwise expressing bias regarding a customer’s choice of one fuel over another.~~

23. ~~“Incremental benefits” means amounts saved through avoiding costs for fuel, purchased power, new capacity, transmission, distribution, and other cost items necessary to provide electric utility service, along with other improvements in societal welfare, such as through avoided environmental impacts, including, but not limited to, water consumption savings, air emission reduction, reduction in coal ash, and reduction of nuclear waste.~~
24. ~~“Incremental costs” means the additional expenses of DSM measures, relative to baseline.~~
25. ~~“Independent program administrator” means an impartial third party employed to provide objective oversight of energy efficiency programs.~~
26. ~~“kW” means kilowatt.~~
27. ~~“kWh” means kilowatt-hour.~~
28. ~~“Leveraging” means combining resources to more effectively achieve an energy efficiency goal, or to achieve greater energy efficiency savings, than would be achieved without combining resources.~~
29. ~~“Load management” means actions taken or sponsored by an affected utility to reduce peak demands or improve system operating efficiency, such as direct control of customer demands through affected-utility-initiated interruption or cycling, thermal storage, or educational campaigns to encourage customers to shift loads.~~
30. ~~“Low-income customer” means a customer with a below average level of household income, as defined in an affected utility’s Commission-approved DSM program description.~~
31. ~~“Market transformation” means strategic efforts to induce lasting structural or behavioral changes in the market that result in increased energy efficiency.~~
32. ~~“Net benefits” means the incremental benefits resulting from DSM minus the incremental costs of DSM.~~
33. ~~“Non-market benefits” means improvements in societal welfare that are not bought or sold.~~
34. ~~“Program costs” means the expenses incurred by an affected utility as a result of developing, marketing, implementing, administering, and evaluating Commission-approved DSM programs.~~
35. ~~“Self direction” means an option made available to qualifying customers of sufficient size, in which the amount of money paid by each qualifying customer toward DSM costs is tracked for the customer and made available for use by the customer for approved DSM investments upon application by the customer.~~



36. ~~“Societal Test” means a cost-effectiveness test of the net benefits of DSM programs that starts with the Total Resource Cost Test, but includes non-market benefits and costs to society.~~
37. ~~“Staff” means individuals working for the Commission’s Utilities Division, whether as employees or through contract.~~
38. ~~“Thermal envelope” means the collection of building surfaces, such as walls, windows, doors, floors, ceilings, and roofs, that separate interior conditioned (heated or cooled) spaces from the exterior environment.~~
39. ~~“Total Resource Cost Test” means a cost-effectiveness test that measures the net benefits of a DSM program as a resource option, including incremental measure costs, incremental affected utility costs, and carrying costs as a component of avoided capacity cost, but excluding incentives paid by affected utilities and non-market benefits to society.~~

**~~R14-2-2402. Applicability~~**

~~This Article applies to each affected utility classified as Class A according to R14-2-103(A)(3)(q), unless the affected utility is an electric distribution cooperative that has fewer than 25% of its customers in Arizona.~~

**~~R14-2-2403. Goals and Objectives~~**

~~A. An affected utility shall design each DSM program:~~

- ~~1. To be cost-effective, and~~
- ~~2. To accomplish at least one of the following:~~
  - ~~a. Energy efficiency,~~
  - ~~b. Load management, or~~
  - ~~c. Demand response.~~

~~B. An affected utility shall consider the following when planning and implementing a DSM program:~~

- ~~1. Whether the DSM program will achieve cost-effective energy savings and peak demand reductions;~~
- ~~2. Whether the DSM program will advance market transformation and achieve sustainable savings, reducing the need for future market interventions; and~~
- ~~3. Whether the affected utility can ensure a level of funding adequate to sustain the DSM program and allow the DSM program to achieve its targeted goal.~~

~~C. An affected utility shall:~~

- ~~1. Offer DSM programs that will provide an opportunity for all affected utility customer segments to participate, and~~
- ~~2. Allocate a portion of DSM resources specifically to low-income customers.~~

**~~R14-2-2404. Energy Efficiency Standards~~**

- ~~A. Except as provided in R14-2-2418, in order to ensure reliable electric service at reasonable ratepayer rates and costs, by December 31, 2020, an affected utility shall, through cost-effective DSM energy efficiency programs, achieve cumulative annual energy savings, measured in kWh, equivalent to at least 22% of the affected utility's retail electric energy sales for calendar year 2019.~~
- ~~B. An affected utility shall, by the end of each calendar year, meet at least the cumulative annual energy efficiency standard listed in Table 1 for that calendar year. An illustrative example of how the required energy savings would be calculated is shown in Table 2. An illustrative example of how the standard could be met in 2020 is shown in Table 4.~~

**~~Table 1. Energy Efficiency Standard~~**

<del>CALENDAR YEAR</del>	<del>ENERGY EFFICIENCY STANDARD</del>
	<del>(Cumulative Annual Energy Savings by the End of Each Calendar Year as a Percentage of the Retail Energy Sales in the Prior Calendar Year)</del>
<del>2011</del>	<del>1.25%</del>
<del>2012</del>	<del>3.00%</del>

2013	5.00%
2014	7.25%
2015	9.50%
2016	12.00%
2017	14.50%
2018	17.00%
2019	19.50%
2020	22.00%

**Table 2. Illustrative Example of Calculating Required Energy Savings**

CALENDAR YEAR	A RETAIL SALES (kWh)	B ENERGY EFFICIENCY STANDARD (B of current year × A of prior year)	C REQUIRED CUMULATIVE ENERGY SAVINGS (B of current year × A of prior year)
2010	100,000,000	0	0

2011	100,750.0	1.25%	1,250,000
	00		
2012	101,017.5	3.00%	3,022,500
	00		
2013	101,069.9	5.00%	5,050,875
	25		
2014	100,915.6	7.25%	7,327,570
	46		
2015	100,821.0	9.50%	9,586,986
	94		
2016	100,517.7	12.00%	12,098,531
	11		
2017	100,293.4	14.50%	14,575,068
	99		
2018	100,116.0	17.00%	17,049,895
	43		
2019	99,986.62	19.50%	19,522,628
	8		
2020	99,902.38	22.00%	21,997,058
	4		

~~C. An affected utility's measured reductions in peak demand resulting from cost effective demand response and load management programs may comprise up to two percentage points of the 22% energy efficiency standard, with peak demand reduction capability from demand response converted to an annual energy savings equivalent based on an assumed 50% annual load factor. The credit for demand response and load management peak demand reductions shall not exceed 10% of the energy efficiency standard set forth in subsection (B) for any year. The measured reductions in peak demand occurring during a calendar year after the effective date of this Article may be counted for that calendar year~~

even if the demand response or load management program resulting in the reductions was implemented prior to the effective date of this Article.

~~D. An affected utility's energy savings resulting from DSM energy efficiency programs implemented before the effective date of this Article, but after 2004, may be credited toward meeting the energy efficiency standard set forth in subsection (B). The total energy savings credit for these pre-rules energy efficiency programs shall not exceed 4% of the affected utility's retail energy sales in calendar year 2005. A portion of the total energy savings credit for these pre-rules energy efficiency programs may be applied each year, from 2016 through 2020, as listed in Table 3, Column A.~~

**Table 3. Credit for Pre-Rules Energy Savings**

CALENDAR YEAR	A	B
	CREDIT FOR THE PRE-RULES ENERGY SAVINGS APPLIED IN EACH YEAR (Percentage of the Total Eligible Pre-Rules Cumulative Annual Energy Savings That Shall Be Applied in the Year)	CUMULATIVE APPLICATION OF THE CREDIT FOR THE PRE-RULES ENERGY SAVINGS IN 2016-2020 (Percentage of the Total Eligible Pre-Rules Cumulative Annual Energy Savings That Are Credited by the End of Each Year)
2016	7.5%	7.5%
2017	15.0%	22.5%
2018	20.0%	42.5%
2019	25.0%	67.5%
2020	32.5%	100.0%

~~E. An affected utility may count toward meeting the standard up to one third of the energy savings, resulting from energy efficiency building codes, that are quantified and reported through a measurement and evaluation study undertaken by the affected utility.~~

- ~~F. An affected utility may count the energy savings from combined heat and power (CHP) installations that do not qualify under the Renewable Energy Standard toward meeting the energy efficiency standard.~~
- ~~G. An affected utility may count a customer's energy savings resulting from self direction toward meeting the standard.~~
- ~~H. An affected utility's energy savings resulting from efficiency improvements to its delivery system may not be counted toward meeting the standard.~~
- ~~I. An affected utility's energy savings used to meet the energy efficiency standard will be assumed to continue through the year 2020 or, if expiring before the year 2020, to be replaced with a DSM energy efficiency program having at least the same level of efficiency.~~

**Table 4. Illustrative Example of How the Energy Standard Could Be Met in 2020**

	<b>2020 Energy Efficiency Standard</b>	<b>2019 Retail Sales (kWh)</b>	<b>Required Cumulative Annual Energy Savings (kWh)</b>
Total	22.00%	99,986,628	21,997,058

**Breakdown of Savings and Credits Used To Meet 2020 Standard:**

	<b>Cumulative Annual Energy Savings or Credit (kWh)</b>
<b>Demand Response Credit</b> Up to 2.00% R14-2-2404(C)	1,999,733
<b>Pre-rules Savings Credit</b> R14-2-2404(D)	1,100,000*
<b>Building Code</b> R14-2-2404(E)	1,000,000



CHP	500,000
R14-2-2404(F)	
Self-direction	100,000
R14-2-2404(G)	
Energy Efficiency	17,297,325
R14-2-2404(A)	
Total	21,997,058

\* ~~The total pre-rules savings credit is capped at 4% of 2005 retail energy sales, and the total credit is allocated over five years from 2016 to 2020. The credit shown above represents an estimate of the portion of the total credit that can be taken in 2020, or 32.5% of the total credit allowed.~~

#### **R14-2-2405. Implementation Plans**

- ~~A. Except as provided in R14-2-2418, on June 1 of each odd year, or annually at the election of each affected utility, each affected utility shall file with Docket Control, for Commission review and approval, an implementation plan describing how the affected utility intends to meet the energy efficiency standard for the next one or two calendar years, as applicable, except that the initial implementation plan shall be filed within 30 days of the effective date of this Article.~~
- ~~B. The implementation plan shall include the following information:~~
- ~~1. Except for the initial implementation plan, a description of the affected utility's compliance with the requirements of this Article for the previous calendar year;~~
  - ~~2. Except for the initial implementation plan, which shall describe only the next calendar year, a description of how the affected utility intends to comply with this Article for the next two calendar years, including an explanation of any modification to the rates of an existing DSM adjustment mechanism or tariff that the affected utility believes is necessary;~~
  - ~~3. Except for the initial implementation plan, which shall describe only the next calendar year, a description of each DSM program to be newly implemented or continued in the next two calendar~~

~~years and an estimate of the annual kWh and kW savings projected to be obtained through each DSM program;~~

- ~~4. The estimated total cost and cost per kWh reduction of each DSM measure and DSM program described in subsection (B)(3);~~
  - ~~5. A DSM tariff filing complying with R14-2-2406(A) or a request to modify and reset an adjustment mechanism complying with R14-2-2406(C), as applicable; and~~
  - ~~6. For each new DSM program or DSM measure that the affected utility desires to implement, a program proposal complying with R14-2-2407.~~
- ~~C. An affected utility shall notify its customers of its annual implementation plan filing through a notice in its next regularly scheduled customer bills.~~
- ~~D. The Commission may hold a hearing to determine whether an affected utility's implementation plan satisfies the requirements of this Article.~~
- ~~E. An affected utility's Commission-approved implementation plan, and the DSM programs authorized thereunder, shall continue in effect until the Commission takes action on a new implementation plan for the affected utility.~~

#### **~~R14-2-2406. DSM Tariffs~~**

~~A. An affected utility's DSM tariff filing shall include the following:~~

- ~~1. A detailed description of each method proposed by the affected utility to recover the reasonable and prudent costs associated with implementing the affected utility's intended DSM programs;~~
- ~~2. Financial information and supporting data sufficient to allow the Commission to determine the affected utility's fair value, including, at a minimum, the information required to be submitted in a utility annual report filed under R14-2-212(G)(4);~~
- ~~3. Data supporting the level of costs that the affected utility believes will be incurred in order to comply with this Article; and~~
- ~~4. Any other information that the Commission believes is relevant to the Commission's consideration of the tariff filing.~~

- ~~B. The Commission shall approve, modify, or deny a tariff filed pursuant to subsection (A) within 180 days after the tariff has been filed. The Commission may suspend this deadline or adopt an alternative procedural schedule for good cause.~~
- ~~C. If an affected utility has an existing adjustment mechanism to recover the reasonable and prudent costs associated with implementing DSM programs, the affected utility may, in lieu of making a tariff filing under subsection (A), file a request to modify and reset its adjustment mechanism by submitting the information required under subsections (A)(1) and (3).~~

**~~R14-2-2407. Commission Review and Approval of DSM Programs and DSM Measures~~**

- ~~A. An affected utility shall obtain Commission approval before implementing a new DSM program or DSM measure.~~
- ~~B. An affected utility may apply for Commission approval of a DSM program or DSM measure by submitting a program proposal either as part of its implementation plan submitted under R14-2-2405 or through a separate application.~~
- ~~C. A program proposal shall include the following:~~
- ~~1. A description of the DSM program or DSM measure that the affected utility desires to implement,~~
  - ~~2. The affected utility's objectives and rationale for the DSM program or DSM measure,~~
  - ~~3. A description of the market segment at which the DSM program or DSM measure is aimed,~~
  - ~~4. An estimated level of customer participation in the DSM program or DSM measure,~~
  - ~~5. An estimate of the baseline,~~
  - ~~6. The estimated societal benefits and savings from the DSM program or DSM measure,~~
  - ~~7. The estimated societal costs of the DSM program or DSM measure,~~
  - ~~8. The estimated environmental benefits to be derived from the DSM program or DSM measure,~~
  - ~~9. The estimated benefit-cost ratio of the DSM program or DSM measure,~~
  - ~~10. The affected utility's marketing and delivery strategy,~~
  - ~~11. The affected utility's estimated annual costs and budget for the DSM program or DSM measure,~~
  - ~~12. The implementation schedule for the DSM program or DSM measure,~~
  - ~~13. A description of the affected utility's plan for monitoring and evaluating the DSM program or DSM measure, and~~

~~14. Any other information that the Commission believes is relevant to the Commission's consideration of the tariff filing.~~

~~D. In determining whether to approve a program proposal, the Commission shall consider:~~

- ~~1. The extent to which the Commission believes the DSM program or DSM measure will meet the goals set forth in R14-2-2403(A), and~~
- ~~2. All of the considerations set forth in R14-2-2403(B).~~

~~E. Staff may request modifications of on-going DSM programs to ensure consistency with this Article. The Commission shall allow affected utilities adequate time to notify customers of DSM program modifications.~~

**~~R14-2-2408. Parity and Equity~~**

- ~~A. An affected utility shall develop and propose DSM programs for residential, non-residential, and low-income customers.~~
- ~~B. An affected utility shall allocate DSM funds collected from residential customers and from non-residential customers proportionately to those customer classes to the extent practicable.~~
- ~~C. The affected utility costs of DSM programs for low-income customers shall be borne by all customer classes, except where a customer or customer class is specifically exempted by Commission order.~~
- ~~D. DSM funds collected by an affected utility shall be used, to the extent practicable, to benefit that affected utility's customers.~~
- ~~E. All customer classes of an affected utility shall bear the costs of DSM programs by payment through a non-bypassable mechanism, unless a customer or customer class is specifically exempted by Commission order.~~

**~~R14-2-2409. Reporting Requirements~~**

- ~~A. By March 1 of each year, an affected utility shall submit to the Commission, in a Commission-established docket for that year, a DSM progress report providing information for each of the affected utility's Commission-approved DSM programs and including at least the following:~~
  - ~~1. An analysis of the affected utility's progress toward meeting the annual energy efficiency standard;~~

- ~~2. A list of the affected utility's current Commission-approved DSM programs and DSM measures, organized by customer segment;~~
- ~~3. A description of the findings from any research projects completed during the previous year; and~~
- ~~4. The following information for each Commission-approved DSM program or DSM measure:~~
  - ~~a. A brief description;~~
  - ~~b. Goals, objectives, and savings targets;~~
  - ~~c. The level of customer participation during the previous year;~~
  - ~~d. The costs incurred during the previous year, disaggregated by type of cost, such as administrative costs, rebates, and monitoring costs;~~
  - ~~e. A description and the results of evaluation and monitoring activities during the previous year;~~
  - ~~f. Savings realized in kW, kWh, therms, and BTUs, as appropriate;~~
  - ~~g. The environmental benefits realized, including reduced emissions and water savings;~~
  - ~~h. Incremental benefits and net benefits, in dollars;~~
  - ~~i. Performance incentive calculations for the previous year;~~
  - ~~j. Problems encountered during the previous year and proposed solutions;~~
  - ~~k. A description of any modifications proposed for the following year; and~~
  - ~~l. Whether the affected utility proposes to terminate the DSM program or DSM measure and the proposed date of termination.~~
- ~~B. By September 1 of each year, an affected utility shall file a status report including a tabular summary showing the following for each current Commission-approved DSM program and DSM measure of the affected utility:~~
  - ~~1. Semi-annual expenditures compared to annual budget, and~~
  - ~~2. Participation rates.~~
- ~~C. An affected utility shall file each report required by this Section with Docket Control, where it will be available to the public, and shall make each such report available to the public upon request.~~
- ~~D. An affected utility may request within its implementation plan that these reporting requirements supersede specific existing DSM reporting requirements.~~

**R14-2-2410. Cost Recovery**

- ~~A. An affected utility may recover the costs that it incurs in planning, designing, implementing, and evaluating a DSM program or DSM measure if the DSM program or DSM measure is all of the following:~~
- ~~1. Approved by the Commission before it is implemented,~~
  - ~~2. Implemented in accordance with a Commission-approved program proposal or implementation plan, and~~
  - ~~3. Monitored and evaluated for cost-effectiveness pursuant to R14-2-2415.~~
- ~~B. An affected utility shall monitor and evaluate each DSM program and DSM measure, as provided in R14-2-2415, to determine whether the DSM program or DSM measure is cost-effective and otherwise meets expectations.~~
- ~~C. If an affected utility determines that a DSM program or DSM measure is not cost effective or otherwise does not meet expectations, the affected utility shall include in its annual DSM progress report filed under R14-2-2409 a proposal to modify or terminate the DSM program or DSM measure.~~
- ~~D. An affected utility shall recover its DSM costs concurrently, on an annual basis, with the spending for a DSM program or DSM measure, unless the Commission orders otherwise.~~
- ~~E. An affected utility may recover costs from DSM funds for any of the following items, if the expenditures will enhance DSM:~~
- ~~1. Incremental labor attributable to DSM development,~~
  - ~~2. A market study,~~
  - ~~3. A research and development project such as applied technology assessment,~~
  - ~~4. Consortium membership, or~~
  - ~~5. Another item that is difficult to allocate to an individual DSM program.~~
- ~~F. The Commission may impose a limit on the amount of DSM funds that may be used for the items in subsection (E).~~
- ~~G. If goods and services used by an affected utility for DSM have value for other affected utility functions, programs, or services, the affected utility shall divide the costs for the goods and services and allocate funding proportionately.~~
- ~~H. An affected utility shall allocate DSM costs in accordance with generally accepted accounting principles.~~



- ~~I. The Commission shall review and address financial disincentives, recovery of fixed costs, and recovery of net lost income/revenue, due to Commission-approved DSM programs, if an affected utility requests such review in its rate case and provides documentation/records supporting its request in its rate application.~~
- ~~J. An affected utility, at its own initiative, may submit to the Commission twice annual reports on the financial impacts of its Commission-approved DSM programs, including any unrecovered fixed costs and net lost income/revenue resulting from its Commission-approved DSM programs.~~

**~~R14-2-2411. Performance Incentives~~**

~~In the implementation plans required by R14-2-2405, an affected utility may propose for Commission review a performance incentive to assist in achieving the energy efficiency standard set forth in R14-2-2404. The Commission may also consider performance incentives in a general rate case.~~

**~~R14-2-2412. Cost-effectiveness~~**

- ~~A. An affected utility shall ensure that the incremental benefits to society of the affected utility's overall DSM portfolio exceed the incremental costs to society of the DSM portfolio.~~
- ~~B. The Societal Test shall be used to determine cost-effectiveness.~~
- ~~C. The analysis of a DSM program's or DSM measure's cost-effectiveness may include:~~
  - ~~1. Costs and benefits associated with reliability, improved system operations, environmental impacts, and customer service;~~
  - ~~2. Savings of both natural gas and electricity; and~~
  - ~~3. Any uncertainty about future streams of costs or benefits.~~
- ~~D. An affected utility shall make a good faith effort to quantify water consumption savings and air emission reductions, while other environmental costs or the value of environmental improvements shall be estimated in physical terms when practical but may be expressed qualitatively. An affected utility, Staff, or any party may propose monetized benefits and costs if supported by appropriate documentation or analyses.~~
- ~~E. Market transformation programs shall be analyzed for cost-effectiveness by measuring market effects compared to program costs.~~

- ~~F. Educational programs shall be analyzed for cost-effectiveness based on estimated energy and peak demand savings resulting from increased awareness about energy use and opportunities for saving energy.~~
- ~~G. Research and development and pilot programs are not required to demonstrate cost-effectiveness.~~
- ~~H. An affected utility's low income customer program portfolio shall be cost-effective, but costs attributable to necessary health and safety measures shall not be used in the calculation.~~

**~~R14-2-2413. Baseline Estimation~~**

- ~~A. To determine the baseline, an affected utility shall estimate the level of electric demand and consumption and the associated costs that would have occurred in the absence of a DSM program or DSM measure.~~
- ~~B. For demand response programs, an affected utility shall use customer load profile information to verify baseline consumption patterns and the peak demand savings resulting from demand response actions.~~
- ~~C. For installations or applications that have multiple fuel choices, an affected utility shall determine the baseline using the same fuel source actually used for the installation or application.~~

**~~R14-2-2414. Fuel Neutrality~~**

- ~~A. Ratepayer funded DSM shall be developed and implemented in a fuel neutral manner.~~
- ~~B. An affected utility shall use DSM funds collected from electric customers for electric DSM programs, unless otherwise ordered by the Commission.~~
- ~~C. An affected utility may use DSM funds collected from electric customers for thermal envelope improvements.~~

**~~R14-2-2415. Monitoring, Evaluation, and Research~~**

- ~~A. An affected utility shall monitor and evaluate each DSM program and DSM measure to:~~
  - ~~1. Ensure compliance with the cost-effectiveness requirements of R14-2-2412;~~
  - ~~2. Determine participation rates, energy savings, and demand reductions;~~
  - ~~3. Assess the implementation process for the DSM program or DSM measure;~~

- ~~4. Obtain information on whether to continue, modify, or terminate a DSM program or DSM measure;  
and~~
- ~~5. Determine the persistence and reliability of the affected utility's DSM.~~
- ~~B. An affected utility may conduct evaluation and research, such as market studies, market research, and other technical research, for DSM program planning, product development, and DSM program improvement.~~

**~~R14-2-2416. Program Administration and Implementation~~**

- ~~A. An affected utility may use an energy service company or other external resource to implement a DSM program or DSM measure.~~
- ~~B. The Commission may, at its discretion, establish independent program administrators who would be subject to the relevant requirements of this Article.~~

**~~R14-2-2417. Leveraging and Cooperation~~**

- ~~A. An affected utility shall, to the extent practicable, participate in cost sharing, leveraging, or other lawful arrangements with customers, vendors, manufacturers, government agencies, other electric utilities, or other entities if doing so will increase the effectiveness or cost effectiveness of a DSM program or DSM measure.~~
- ~~B. An affected utility shall participate in a DSM program or DSM measure with a natural gas utility when doing so is practicable and if doing so will increase the effectiveness or cost effectiveness of a DSM program or DSM measure.~~

**~~R14-2-2418. Compliance by Electric Distribution Cooperatives~~**

- ~~A. An electric distribution cooperative that is an affected utility shall comply with the requirements of this Section instead of meeting the requirements of R14-2-2404(A) and (B) and R14-2-2405(A).~~
- ~~B. An electric distribution cooperative shall, on June 1 of each odd year, or annually at its election:
  - ~~1. File with Docket Control, for Commission review and approval, an implementation plan for each DSM program to be implemented or maintained during the next one or two calendar years, as applicable;  
and~~~~

2. ~~Submit to the Director of the Commission's Utilities Division an electronic copy of its implementation plan in a format suitable for posting on the Commission's web site.~~
- C. ~~An implementation plan submitted under subsection (B) shall set forth an energy efficiency goal for each year of at least 75% of the savings requirement specified in R14-2-2404 and shall include the information required under R14-2-2405(B).~~

**~~R14-2-2419. Waiver from the Provisions of this Article~~**

- A. ~~The Commission may waive compliance with any provision of this Article for good cause.~~
- B. ~~An affected utility may petition the Commission to waive its compliance with any provision of this Article for good cause.~~
- C. ~~A petition filed pursuant to this Section shall have priority over other matters filed under this Article.~~

**ARTICLE 25. GAS UTILITY ENERGY EFFICIENCY STANDARDS**

**~~R14-2-2501. Definitions~~**

In this Article, unless otherwise specified:

1. ~~"Adjustment mechanism" means a Commission-approved provision in an affected utility's rate schedule allowing the affected utility to increase and decrease a certain rate or rates, in an established manner, when increases and decreases in specific costs are incurred by the affected utility.~~
2. ~~"Affected utility" means a public service corporation that provides gas utility service to retail customers in Arizona.~~
3. ~~"Baseline" means the level of gas demand, gas consumption, and associated expenses estimated to occur in the absence of a specific DSM program, determined as provided in R14-2-2513.~~
4. ~~"CHP" means combined heat and power, which is using a primary energy source to simultaneously produce electrical energy and useful process heat.~~
5. ~~"Commission" means the Arizona Corporation Commission.~~
6. ~~"Cost-effective" means that total incremental benefits from a DSM measure or DSM program exceed total incremental costs over the life of the DSM measure, as determined under R14-2-2512.~~

7. ~~“Customer” means the person or entity in whose name service is rendered to a single contiguous field, location, or facility, regardless of the number of meters at the field, location, or facility.~~
8. ~~“Delivery system” means the infrastructure through which an affected utility transmits and then distributes gas energy to its customers.~~
9. ~~“DSM” means demand-side management, the implementation and maintenance of one or more DSM programs.~~
10. ~~“DSM measure” means any material, device, technology, educational program, practice, or facility alteration designed to result in increased energy efficiency and includes CHP used to displace space heating, water heating, or another load.~~
11. ~~“DSM program” means one or more DSM measures provided as part of a single offering to customers.~~
12. ~~“DSM tariff” means a Commission approved schedule of rates designed to recover an affected utility’s reasonable and prudent costs of complying with this Article.~~
13. ~~“Energy efficiency” means the production or delivery of an equivalent level and quality of end-use gas service using less energy, or the conservation of energy by end-use customers.~~
14. ~~“Energy efficiency standard” means the reduction in retail energy sales, in percentage of therms or therm equivalents, required to be achieved through an affected utility’s approved DSM and RET programs as prescribed in R14-2-2504.~~
15. ~~“Energy savings” means the reduction in a customer’s energy consumption, expressed in therms or therm equivalents.~~
16. ~~“Energy service company” means a company that provides a broad range of services related to energy efficiency, including energy audits, the design and implementation of energy efficiency projects, and the installation and maintenance of energy efficiency measures.~~
17. ~~“Environmental benefits” means avoidance of costs for compliance, or reduction in environmental impacts, for things such as, but not limited to:~~
  - a. ~~Water use and water contamination;~~
  - b. ~~Monitoring storage and disposal of solid waste, such as coal ash (bottom and fly);~~
  - c. ~~Health effects from burning fossil fuels; and~~
  - d. ~~Emissions from transportation and production of fuels.~~

18. ~~"Fuel-neutral" means without promoting or otherwise expressing bias regarding a customer's choice of one fuel over another.~~
19. ~~"Gas" means either natural gas or propane.~~
20. ~~"Gas utility" means a public service corporation providing natural gas service or propane service to the public.~~
21. ~~"Incremental benefits" means amounts saved through avoiding costs for gas purchases, delivery system, and other cost items necessary to provide gas utility service, along with other improvements in societal welfare, such as through avoided environmental impacts, including, but not limited to, water consumption savings, water contamination reduction, air emission reduction, reduction in coal ash, and reduction of nuclear waste.~~
22. ~~"Incremental costs" means the additional expenses of DSM measures, relative to baseline.~~
23. ~~"Independent program administrator" means an impartial third party employed to provide objective oversight of DSM and RET programs.~~
24. ~~"kWh" means kilowatt-hour.~~
25. ~~"Leveraging" means combining resources to more effectively achieve an energy efficiency goal, or to achieve greater energy efficiency savings, than would be achieved without combining resources.~~
26. ~~"Low income customer" means a customer with a below average level of household income, as defined in an affected utility's Commission-approved DSM program description.~~
27. ~~"Market transformation" means strategic efforts to induce lasting structural or behavioral changes in the market that result in increased energy efficiency.~~
28. ~~"Net benefits" means the incremental benefits resulting from DSM minus the incremental costs of DSM.~~
29. ~~"Non-market benefits" means improvements in societal welfare that are not bought or sold.~~
30. ~~"Program costs" means the expenses incurred by an affected utility as a result of developing, marketing, implementing, administering, and evaluating Commission-approved DSM programs.~~
31. ~~"RET" means a renewable energy resource technology application utilizing an energy resource that is replaced rapidly by a natural, ongoing process and that displaces conventional energy resources otherwise used to provide energy to an affected utility's Arizona customers.~~
32. ~~"RET program" means one or more RETs provided as part of a single offering to customers.~~



33. ~~“Revenue decoupling” means a mechanism that reduces or eliminates the connection between sales volume and the recovery of an affected utility’s Commission-approved cost of service.~~
34. ~~“Self direction” means an option made available to qualifying customers of sufficient size, in which the amount of money paid by each qualifying customer toward DSM costs is tracked for the customer and made available for use by the customer for approved DSM investments upon application by the customer.~~
35. ~~“Societal Test” means a cost-effectiveness test of the net benefits of DSM programs that starts with the Total Resource Cost Test, but includes non-market benefits and costs to society.~~
36. ~~“Staff” means individuals working for the Commission’s Utilities Division, whether as employees or through contract.~~
37. ~~“Therm” means a unit of heat energy equal to 100,000 British Thermal Units.~~
38. ~~“Thermal envelope” means the collection of building surfaces, such as walls, windows, doors, floors, ceilings, and roofs, that separate interior conditioned (heated or cooled) spaces from the exterior environment.~~
39. ~~“Therm equivalent” means a unit of energy, such as kWh, converted and stated in terms of therms.~~
40. ~~“Total Resource Cost Test” means a cost-effectiveness test that measures the net benefits of a DSM program as a resource option, including incremental measure costs, incremental affected utility costs, and carrying costs as a component of avoided capacity cost, but excluding incentives paid by affected utilities and non-market benefits to society.~~

#### **~~R14-2-2502. Applicability~~**

~~This Article applies to each affected utility classified as Class A according to R14-2-103(A)(3)(q).~~

#### **~~R14-2-2503. Goals and Objectives~~**

- ~~A. An affected utility shall design each DSM program to be cost-effective.~~
- ~~B. An affected utility shall consider the following when planning and implementing a DSM or RET program:~~
- ~~1. Whether the DSM or RET program will advance market transformation and achieve sustainable savings, reducing the need for future market interventions;~~

2. Whether the affected utility can ensure a level of funding adequate to sustain the DSM or RET program and allow the program to achieve its targeted goals; and

3. If a DSM program, whether the DSM program will achieve cost-effective energy savings.

C. An affected utility shall:

1. Offer DSM programs that will provide an opportunity for all affected utility customer segments to participate; and

2. Allocate a portion of DSM resources specifically to low income customers.

**~~R14-2-2504. Energy Efficiency Standards~~**

A. Except as provided in R14-2-2518 and R14-2-2519, in order to ensure reliable gas service at reasonable ratepayer rates and costs, by December 31, 2020, an affected utility shall, through DSM and RET programs, achieve cumulative annual energy savings, expressed as therms or therm equivalents, equal to at least 6% of the affected utility's retail gas energy sales for calendar year 2019.

B. An affected utility shall, by the end of each calendar year, meet at least the cumulative annual energy efficiency standard listed in Table 1 for that calendar year. An illustrative example of how the required energy savings would be calculated is shown in Table 2. An illustrative example of how the standard can be met in 2020 is shown in Table 4.

**~~Table 1. — Energy Efficiency Standard~~**

CALENDAR YEAR	ENERGY EFFICIENCY STANDARD
	(Cumulative Annual Energy Savings by the End of Each Calendar _____ Year _____ as _____ a Percentage of the Retail Energy Sales in the Prior Calendar Year)
2011	0.50%
2012	1.20%
2013	1.80%
2014	2.40%

2015	3.00%
2016	3.60%
2017	4.20%
2018	4.80%
2019	5.40%
2020	6.00%

**Table 2. Illustrative Example of Calculating Required Energy Savings**

<b>CALENDAR YEAR</b>	<b>A RETAIL SALES (therms)</b>	<b>B ENERGY EFFICIENCY STANDARD</b>	<b>C REQUIRED CUMULATIVE ENERGY SAVINGS (therms or therm equivalents) (B of current year × A of prior year)</b>
2010	100,000,000		0
2011	97,500,000	0.50%	500,000
2012	94,870,000	1.20%	1,170,000
2013	92,411,540	1.80%	1,707,660
2014	90,018,939	2.40%	2,217,877
2015	87,691,512	3.00%	2,700,568
2016	85,427,344	3.60%	3,156,894
2017	83,224,605	4.20%	3,587,948
2018	81,081,521	4.80%	3,994,781
2019	78,996,374	5.40%	4,378,402

2020	76,967,498	6.00%	4,739,782
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- ~~C. An affected utility may count energy savings resulting from DSM and RET programs to meet the energy efficiency standard. At least 75% of the energy efficiency standard for each year listed in Table 1 shall be achieved through DSM energy efficiency programs.~~
- ~~D. An affected utility's energy savings resulting from DSM energy efficiency programs implemented before the effective date of this Article, but after 2004, may be credited toward meeting the energy efficiency standard set forth in subsection (B). The total energy savings credit for these pre-rules DSM programs shall not exceed 1% of the affected utility's retail energy sales in calendar year 2005. A portion of the total energy savings credit for these pre-rules programs may be applied each year, from 2016 through 2020, as listed in Table 3, Column A.~~

~~Table 3. Credit for Pre-rules Energy Savings~~

CALENDAR YEAR	A CREDIT FOR THE PRE-RULES ENERGY SAVINGS APPLIED IN EACH YEAR (Percentage of the Total Eligible Pre-rules Cumulative Annual Energy Savings That Shall Be Applied in the Year)	B CUMULATIVE APPLICATION OF THE CREDIT FOR THE PRE-RULES ENERGY SAVINGS IN 2016-2020 (Percentage of the Total Eligible Pre-rules Cumulative Annual Energy Savings That Are Credited by the End of Each Year)
2016	7.5%	7.5%
2017	15.0%	22.5%
2018	20.0%	42.5%
2019	25.0%	67.5%

2020	32.5%	100.0%
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- ~~E. An affected utility may count toward meeting the energy efficiency standard up to one third of the energy savings resulting from energy efficiency building codes and up to one third of the energy savings resulting from energy efficiency appliance standards, if the energy savings are quantified and reported through a measurement and evaluation study undertaken by the affected utility, and the affected utility demonstrates and documents its efforts in support of the adoption or implementation of the energy efficiency building codes and appliance standards.~~
- ~~F. An affected utility may count a customer's energy savings resulting from self-direction toward meeting the energy efficiency standard.~~
- ~~G. An affected utility may count toward meeting the energy efficiency standard all energy savings resulting from the affected utility's sponsorship of RET projects that displace gas. An affected utility may also count toward meeting the energy efficiency standard all energy savings resulting from other RET projects that are not sponsored by the affected utility, if the affected utility can demonstrate that its efforts facilitated the placement and completion of the RET project.~~
- ~~H. An affected utility's energy savings resulting from efficiency improvements to its delivery system may not be counted toward meeting the energy efficiency standard.~~
- ~~I. An affected utility's energy savings used to meet the energy efficiency standard will be assumed to continue through the year 2020 or, if expiring before the year 2020, to be replaced with a DSM measure or RET having at least the same level of efficiency.~~

**Table 4. — Illustrative Example of How the Energy Standard Could be Met in 2020**

	2020 Energy Efficiency Standard	2019 Retail — Sales (therms)	Required — Cumulative Annual — Energy Savings (therms or therm-equivalents)
<b>Total</b>	6.00%	78,996,374	4,739,782
<b>Breakdown of Savings and Credits Used To Meet 2020 Standard:</b>			

			<del>Cumulative</del> <del>Annual</del> <del>Energy</del> <del>Savings Or Credit</del> <del>(therms)</del>
<del>Pre-rules Savings</del> <del>Credit</del> R14-2-2504(D)			359,545*
<del>Building Codes and</del> <del>Appliance</del> <del>Standards</del> R14-2-2504(E)			425,000
<del>Self-direction</del> R14-2-2504(F)			27,000
<del>RET</del> R14-2-2504(G)			25,000
<del>CHP</del> R14-2-2501(10) and R14-2-2504(C)			135,000
<del>Energy Efficiency</del> R14-2-2504(C)	At least 75%		3,768,237
<del>Total</del>			4,739,782

\* ~~The total pre-rules savings credit shall be capped at 1% of 2005 retail energy sales, and the total credit is allocated over five years from 2016 to 2020. The credit shown above represents an estimate of the portion of the total credit that can be taken in 2020, or 32.5% of the total credit allowed.~~



**~~R14-2-2505. Implementation Plans~~**

- ~~A. Except as provided in R14-2-2518 and R14-2-2519, on June 1 of each odd year, or annually at the election of each affected utility, each affected utility shall file with Docket Control, for Commission review and approval, an implementation plan describing how the affected utility intends to meet the energy efficiency standard for the next one or two calendar years, as applicable, except that the initial implementation plan shall be filed within 30 days of the effective date of this Article.~~
- ~~B. The implementation plan shall include the following information:~~
- ~~1. Except for the initial implementation plan, a description of the affected utility's compliance with the requirements of this Article for the previous calendar year;~~
  - ~~2. Except for the initial implementation plan, which shall describe only the next calendar year, a description of how the affected utility intends to comply with this Article for the next two calendar years, including an explanation of any modification to the rates of an existing DSM adjustment mechanism or tariff that the affected utility believes is necessary;~~
  - ~~3. Except for the initial implementation plan, which shall describe only the next calendar year, a description of each DSM and RET program to be newly implemented or continued in the next two calendar years and an estimate of the annual therm or therm equivalent savings projected to be obtained through each DSM and RET program;~~
  - ~~4. The estimated total cost and cost per therm reduction of each DSM measure and program and each RET and RET program described in subsection (B)(3);~~
  - ~~5. A DSM tariff filing complying with R14-2-2506(A) or a request to modify and reset an adjustment mechanism complying with R14-2-2506(C), as applicable; and~~
  - ~~6. For each new DSM measure and program and each RET and RET program that the affected utility desires to implement, a program proposal complying with R14-2-2507.~~
- ~~C. An affected utility shall notify its customers of its implementation plan filing through a notice in its next regularly scheduled customer bills following the filing of the implementation plan.~~
- ~~D. The Commission may hold a hearing to determine whether an affected utility's implementation plan satisfies the requirements of this Article.~~

~~E. An affected utility's Commission-approved implementation plan, and the DSM and RET programs authorized thereunder, shall continue in effect until the Commission takes action on a new implementation plan for the affected utility.~~

**~~R14-2-2506. — DSM Tariffs~~**

~~A. An affected utility's DSM tariff filing shall include the following:~~

- ~~1. A detailed description of each method proposed by the affected utility to recover the reasonable and prudent costs associated with implementing the affected utility's intended DSM and RET programs;~~
- ~~2. Financial information and supporting data sufficient to allow the Commission to determine the affected utility's fair value, including, at a minimum, the information required to be submitted in a utility annual report filed under R14-2-312(G)(4);~~
- ~~3. Data supporting the level of costs that the affected utility believes will be incurred in order to comply with this Article; and~~
- ~~4. Any other information that the Commission believes is relevant to the Commission's consideration of the tariff filing.~~

~~B. The Commission shall approve, modify, or deny a tariff filed pursuant to subsection (A) within 180 days after the tariff has been filed. The Commission may suspend this deadline or adopt an alternative procedural schedule for good cause.~~

~~C. If an affected utility has an existing adjustment mechanism to recover the reasonable and prudent costs associated with implementing DSM and RET programs, the affected utility may, in lieu of making a tariff filing under subsection (A), file a request to modify and reset its adjustment mechanism by submitting the information required under subsections (A)(1) and (3).~~

**~~R14-2-2507. — Commission Review and Approval of DSM and RET Programs~~**

~~A. An affected utility shall obtain Commission approval before implementing a new DSM program or measure or a new RET program or RET.~~

~~B. An affected utility may apply for Commission approval of a DSM program or measure or an RET program or RET by submitting a program proposal either as part of its implementation plan submitted under R14-2-2505 or through a separate application.~~

~~C. A program proposal shall include the following:~~

- ~~1. A description of the DSM program or measure or RET program or RET that the affected utility desires to implement;~~
- ~~2. The affected utility's objectives and rationale for the DSM program or measure or RET program or RET;~~
- ~~3. A description of the market segment at which the DSM program or measure or RET program or RET is aimed;~~
- ~~4. An estimated level of customer participation in the DSM program or measure or RET program or RET;~~
- ~~5. An estimate of the baseline;~~
- ~~6. For a DSM program or measure:~~
  - ~~a. The estimated societal benefits and savings from the DSM program or measure;~~
  - ~~b. The estimated societal costs of the DSM program or measure; and~~
  - ~~c. The estimated benefit-cost ratio of the DSM program or measure;~~
- ~~7. The estimated environmental benefits to be derived from the DSM program or measure or RET program or RET;~~
- ~~8. The affected utility's marketing and delivery strategy;~~
- ~~9. The affected utility's estimated annual costs and budget for the DSM program or measure or RET program or RET;~~
- ~~10. The implementation schedule for the DSM program or measure or RET program or RET;~~
- ~~11. A description of the affected utility's plan for monitoring and evaluating the DSM program or measure or RET program or RET; and~~
- ~~12. Any other information that the Commission believes is relevant to the Commission's consideration of the filing.~~

~~D. In determining whether to approve a program proposal, the Commission shall consider:~~

- ~~1. The extent to which the Commission believes the DSM program or measure will meet the goal set forth in R14-2-2503(A), and~~
- ~~2. All of the considerations set forth in R14-2-2503(B).~~

~~E. Staff may request modifications of on-going DSM and RET programs to ensure consistency with this Article. The Commission shall allow affected utilities adequate time to notify customers of DSM and RET program modifications.~~

**~~R14-2-2508. Parity and Equity~~**

- ~~A. An affected utility shall develop and propose DSM programs for residential, non-residential, and low-income customers.~~
- ~~B. An affected utility shall allocate DSM funds collected from residential customers and from non-residential customers proportionately to those customer classes to the extent practicable.~~
- ~~C. The affected utility costs of DSM and RET programs for low-income customers shall be borne by all customer classes, except where a customer or customer class is specifically exempted by Commission order.~~
- ~~D. DSM funds collected by an affected utility shall be used, to the extent practicable, to benefit that affected utility's customers.~~
- ~~E. All customer classes of an affected utility shall bear the costs of DSM and RET programs by payment through a non-bypassable mechanism, unless a customer or customer class is specifically exempted by Commission order.~~

**~~R14-2-2509. Reporting Requirements~~**

- ~~A. By April 1 of each year, an affected utility shall submit to the Commission, in a Commission-established docket for that year, a DSM progress report providing information for each of the affected utility's Commission-approved DSM and RET programs including at least the following:~~
  - ~~1. An analysis of the affected utility's progress toward meeting the annual energy efficiency standard;~~
  - ~~2. A list of the affected utility's current Commission-approved DSM and RET programs, organized by customer segment;~~
  - ~~3. A description of the findings from any research projects completed during the previous year; and~~
  - ~~4. The following information for each Commission-approved DSM program and measure and RET program and RET:~~
    - ~~a. A brief description;~~

- ~~b. Goals, objectives, and savings targets;~~
  - ~~c. The level of customer participation during the previous year;~~
  - ~~d. The costs incurred during the previous year, disaggregated by type of cost, such as administrative costs, rebates, and monitoring costs;~~
  - ~~e. A description and the results of evaluation and monitoring activities during the previous year;~~
  - ~~f. Savings realized in kW, kWh, therms, and therm equivalents, as appropriate;~~
  - ~~g. The environmental benefits realized;~~
  - ~~h. Incremental benefits and net benefits, in dollars;~~
  - ~~i. Performance incentive calculations for the previous year;~~
  - ~~j. Problems encountered during the previous year and proposed solutions;~~
  - ~~k. A description of any modifications proposed for the following year; and~~
  - ~~l. Whether the affected utility proposes to terminate the DSM program or measure or RET program or RET and the proposed date of termination.~~
- ~~B. By October 1 of each year, an affected utility shall file a status report including a tabular summary showing the following for each current Commission-approved DSM program and measure and RET program and RET of the affected utility:~~
- ~~1. Semi-annual expenditures compared to annual budget, and~~
  - ~~2. Participation rates.~~
- ~~C. An affected utility shall file each report required by this Section with Docket Control, where it will be available to the public, and shall make each such report available to the public upon request.~~
- ~~D. An affected utility may request within its implementation plan that these reporting requirements supersede specific existing DSM reporting requirements.~~

**R14-2-2510. Cost Recovery**

- ~~A. An affected utility may recover the costs that it incurs in planning, designing, implementing, and evaluating a DSM program or measure or RET program or RET if the DSM program or measure or RET program or RET is all of the following:~~
- ~~1. Approved by the Commission before it is implemented;~~

- ~~2. Implemented in accordance with a Commission approved program proposal or implementation plan;  
and~~
- ~~3. Monitored and evaluated, pursuant to R14-2-2515.~~
- ~~B. An affected utility shall monitor and evaluate each DSM program or measure and each RET program or RET, as provided in R14-2-2515.~~
- ~~C. If an affected utility determines that a DSM program or measure is not cost-effective or that a DSM program or measure or RET program or RET does not meet expectations, the affected utility shall include in its annual DSM progress report filed under R14-2-2509 a proposal to modify or terminate the DSM program or measure or RET program or RET.~~
- ~~D. An affected utility shall recover its DSM and RET costs concurrently, on an annual basis, with the spending for DSM and RET programs, unless the Commission orders otherwise.~~
- ~~E. An affected utility may recover costs from DSM funds for any of the following items, if the expenditures will enhance DSM or RET programs:~~
  - ~~1. Incremental labor attributable to DSM and RET development,~~
  - ~~2. A market study,~~
  - ~~3. A research and development project such as applied technology assessment,~~
  - ~~4. Consortium membership, or~~
  - ~~5. Other items that are difficult to allocate to an individual DSM or RET program.~~
- ~~F. The Commission may impose a limit on the amount of DSM funds that may be used for the items in subsection (E).~~
- ~~G. If goods and services used by an affected utility for DSM or RET have value for other affected utility functions, programs, or services, the affected utility shall divide the costs for the goods and services and allocate funding proportionately.~~
- ~~H. An affected utility shall allocate DSM and RET costs in accordance with generally accepted accounting principles.~~
- ~~I. An affected utility, at its own initiative, may submit to the Commission twice-annual reports on the financial impacts of its Commission approved DSM and RET programs, including any unrecovered fixed costs and net lost income/revenue resulting from its Commission-approved DSM and RET programs.~~



**~~R14-2-2511. —Revenue Decoupling~~**

~~The Commission shall review and address financial or other disincentives, recovery of fixed costs, and recovery of net lost income/revenue, including, but not limited to, implementation of a revenue decoupling mechanism, due to Commission-approved DSM and RET programs, if an affected utility requests such review in its rate case and provides adequate documentation/records supporting its request in its rate application.~~

**~~R14-2-2512. —Cost-effectiveness~~**

- ~~A. An affected utility shall ensure that the incremental benefits to society of the affected utility's overall group of DSM programs exceed the incremental costs to society of the overall group of DSM programs.~~
- ~~B. The Societal Test shall be used to determine cost-effectiveness.~~
- ~~C. The analysis of a DSM program's or DSM measure's cost-effectiveness may include:~~
  - ~~1. Costs and benefits associated with reliability, improved system operations, environmental impacts, and customer service;~~
  - ~~2. Savings of both gas and electricity; and~~
  - ~~3. Any uncertainty about future streams of costs or benefits.~~
- ~~D. An affected utility shall make a good faith effort to quantify water consumption savings and air emission reductions resulting from implementation of DSM programs, while other environmental costs or the value of environmental improvements shall be estimated in physical terms when practical but may be expressed qualitatively. An affected utility, Staff, or any party may propose monetized benefits and costs if supported by appropriate documentation or analyses.~~
- ~~E. Market transformation programs shall be analyzed for cost-effectiveness by measuring market effects compared to program costs.~~
- ~~F. Educational programs shall be analyzed for cost-effectiveness based on estimated energy and peak demand savings resulting from increased awareness about energy use and opportunities for saving energy.~~
- ~~G. Research and development and pilot programs are not required to demonstrate cost-effectiveness.~~

~~H. An affected utility's low-income customer program portfolio shall be cost effective, but costs attributable to necessary health and safety measures shall not be used in the calculation.~~

**~~R14-2-2513. Baseline Estimation~~**

- ~~A. To determine the baseline, an affected utility shall estimate the level of gas demand and consumption and the associated costs that would have occurred in the absence of a DSM program;~~
- ~~B. For installations or applications that have multiple fuel choices, an affected utility shall determine the baseline using the same fuel source that would have actually been used for the installation or application in the absence of a DSM program.~~

**~~R14-2-2514. Fuel Neutrality~~**

- ~~A. Ratepayer-funded DSM shall be developed and implemented in a fuel-neutral manner;~~
- ~~B. An affected utility shall use DSM funds collected from gas customers for gas DSM programs, unless otherwise ordered by the Commission.~~
- ~~C. An affected utility may use DSM funds collected from gas customers for thermal envelope improvements.~~

**~~R14-2-2515. Monitoring, Evaluation, and Research~~**

- ~~A. An affected utility shall monitor and evaluate each DSM program and measure and each RET program and RET to:~~
- ~~1. Ensure compliance with the cost effectiveness requirements for DSM programs in R14-2-2512;~~
  - ~~2. Determine participation rates, energy savings, and demand reductions;~~
  - ~~3. Assess the implementation process for the DSM program or measure or RET program or RET;~~
  - ~~4. Obtain information on whether to continue, modify, or terminate a DSM program or measure or RET program or RET; and~~
  - ~~5. Determine the persistence and reliability of the affected utility's DSM programs and measures and RET programs and RETs.~~

~~B. An affected utility may conduct evaluation and research, such as market studies, market research, and other technical research, for DSM and RET program planning, product development, and DSM and RET program improvement.~~

**~~R14-2-2516. Program Administration and Implementation~~**

~~A. An affected utility may use an energy service company or other external resource to implement a DSM program or measure or RET program or RET.~~

~~B. The Commission may, at its discretion, establish independent program administrators who would be subject to the relevant requirements of this Article.~~

**~~R14-2-2517. Leveraging and Cooperation~~**

~~A. An affected utility shall, to the extent practicable, participate in cost sharing, leveraging, or other lawful arrangements with customers, vendors, manufacturers, government agencies, other gas utilities, or other entities if doing so will increase the effectiveness of a DSM program or measure or RET program or RET.~~

~~B. An affected utility shall participate in a DSM program or measure or RET program or RET with an electric utility when doing so is practicable and if doing so will increase the effectiveness of the DSM program or measure or RET program or RET.~~

**~~R14-2-2518. Compliance by Gas Distribution Cooperatives~~**

~~A. A gas distribution cooperative that is an affected utility shall comply with the requirements of this Section instead of meeting the requirements of R14-2-2504(A) and (B) and R14-2-2505(A).~~

~~B. A gas distribution cooperative shall, on June 1 of each odd year, or annually at its election:~~

- ~~1. File with Docket Control, for Commission review and approval, an implementation plan providing information for each DSM and RET program to be implemented or maintained during the next one or two calendar years, as applicable; and~~
- ~~2. Submit to the Director of the Commission's Utilities Division an electronic copy of its implementation plan in a format suitable for posting on the Commission's web site.~~

- ~~C. A gas distribution cooperative's initial implementation plan shall be filed with Docket Control within 30 days of the effective date of this Article.~~
- ~~D. An implementation plan submitted under subsection (B) or (C) shall set forth an energy efficiency goal for each year of at least 75% of the savings requirement specified in R14-2-2504 and shall include the information required under R14-2-2505(B).~~

**~~R14-2-2519. Compliance by Propane Companies~~**

- ~~A. A propane company that is an affected utility shall comply with the requirements of this Section instead of meeting the requirements of R14-2-2504(A) and (B) and R14-2-2505(A).~~
- ~~B. A propane company shall, on June 1 of each odd year, or annually at its election:
  - ~~1. File with Docket Control, for Commission review and approval, an implementation plan providing information for each DSM and RET program to be implemented or maintained during the next one or two calendar years, as applicable; and~~
  - ~~2. Submit to the Director of the Commission's Utilities Division an electronic copy of its implementation plan in a format suitable for posting on the Commission's web site.~~~~
- ~~C. A propane company's initial implementation plan shall be filed with Docket Control within 30 days of the effective date of this Article.~~
- ~~D. An implementation plan submitted under subsection (B) or (C) shall set forth an energy efficiency goal for each year of at least 50% of the savings requirement specified in R14-2-2504 and shall include the information required under R14-2-2505(B).~~

**~~R14-2-2520. Waiver from the Provisions of this Article~~**

- ~~A. The Commission may waive compliance with any provision of this Article for good cause.~~
- ~~B. An affected utility may petition the Commission to waive its compliance with any provision of this Article for good cause.~~

TITLE 14. PUBLIC SERVICE CORPORATIONS; CORPORATIONS AND ASSOCIATIONS;  
SECURITIES REGULATION

CHAPTER 2. CORPORATION COMMISSION - FIXED UTILITIES

ARTICLE 16. RETAIL ELECTRIC COMPETITION

Section

~~R14-2-1618. Environmental Portfolio Standard~~

ARTICLE 16. RETAIL ELECTRIC COMPETITION

~~R14-2-1618 Environmental Portfolio Standard~~

~~A. Upon the effective implementation of a Commission-approved Environmental Portfolio Standard Surcharge tariff, any Load Serving Entity selling electricity or aggregating customers for the purpose of selling electricity under the provisions of this Article must derive at least .2% of the total retail energy sold from new solar resources or environmentally friendly renewable electricity technologies, whether that energy is purchased or generated by the seller. Solar resources include photovoltaic resources and solar thermal resources that generate electricity. New solar resources and environmentally friendly renewable electricity technologies are those installed on or after January 1, 1997.~~

~~1. Electric Service Providers, that are not UDCs, are exempt from portfolio requirements until 2004, but could voluntarily elect to participate. ESPs choosing to participate would receive a pro rata share of funds collected from the Environmental Portfolio Surcharge delineated in R14-2-1618.A.2 for portfolio purposes to acquire eligible portfolio systems or electricity generated from such systems.~~

~~2. Utility Distribution Companies would recover part of the costs of the portfolio standard through current System Benefits Charges, if they exist, including a re-allocation of demand side management funding to portfolio uses. Additional portfolio standard costs will be recovered by a customer Environmental Portfolio Surcharge on the customers' monthly bill. The Environmental Portfolio Surcharge shall be assessed monthly to every metered and/or non-metered retail electric service. This monthly assessment will be the lesser of \$0.000875 per kWh or:~~

~~a. Residential Customers: \$.35 per service;~~

~~b. Non-Residential Customers: \$13 per service;~~

~~c. Non-Residential Customers whose metered demand is 3,000 kW or more for three consecutive months: \$39.00 per service. In the case of unmetered services, the Load-Serving~~

~~Entity shall, for purposes of billing the Environmental Portfolio Standard Surcharge and subject to the caps set forth above, use the lesser of (i) the load profile or otherwise estimated kWh required to provide the service in question; or (ii) the service's contract kWh.~~

- ~~3. Customer bills shall reflect a line item entitled "Environmental Portfolio Surcharge, mandated by the Corporation Commission."~~
- ~~4. Utility Distribution Companies or ESPs that do not currently have a renewables program may request a waiver or modification of this Section due to extreme circumstances that may exist.~~

~~B. The portfolio percentage shall increase after December 31, 2000.~~

- ~~1. Starting January 1, 2001, the portfolio percentage shall increase annually and shall be set according to the following schedule:~~

~~YEAR ——— PORTFOLIO PERCENTAGE~~

<del>2001</del>	<del>———.2%</del>
<del>2002</del>	<del>———.4%</del>
<del>2003</del>	<del>———.6%</del>
<del>2004</del>	<del>———.8%</del>
<del>2005</del>	<del>———1.0%</del>
<del>2006</del>	<del>———1.05%</del>
<del>2007-2012</del>	<del>———1.1%</del>

- ~~2. The Commission would continue the annual increase in the portfolio percentage after December 31, 2004, only if the cost of environmental portfolio electricity has declined to a Commission-approved cost/benefit point. The Director, Utilities Division shall establish, not later than January 1, 2003, an Environmental Portfolio Cost Evaluation Working Group to make recommendations to the Commission of an acceptable portfolio electricity cost/benefit point or portfolio kWh cost impact maximum that the Commission could use as a criteria for the decision to continue the increase in the portfolio percentage. The recommendations of the Working Group shall be presented to the Commission not later than June 30, 2003. In no event, however, shall the Commission increase the surcharge caps as delineated in R14-2-1618(A)(2).~~
- ~~3. The requirements for the phase-in of various technologies shall be:~~
  - ~~a. In 2001, the Portfolio kWh makeup shall be at least 50 percent solar electric, and no more than 50 percent other environmentally-friendly renewable electricity technologies or solar hot water or R&D on solar electric resources, but with no more than 10 percent on R&D.~~



- b. ~~In 2002 and 2003, the Portfolio kWh makeup shall be at least 50 percent solar electric, and no more than 50 percent other environmentally friendly renewable electricity technologies or solar hot water or R&D on solar electric resources, but with no more than 5 percent on R&D.~~
- c. ~~In 2004, through 2012, the portfolio kWh makeup shall be at least 60 percent solar electric with no more than 40 percent solar hot water or other environmentally friendly renewable electricity technologies.~~
- C. ~~Load Serving Entities shall be eligible for a number of extra credit multipliers that may be used to meet the portfolio standard requirements. Extra credits may be used to meet portfolio requirements and extra credits from solar electric technologies will also count toward the solar electric fraction requirements in R14-2-1618(B)(3). With the exception of the Early Installation Extra Credit Multiplier, which has a five year life from operational start up, all other extra credit multipliers are valid for the life of the generating equipment.~~
1. ~~Early Installation Extra Credit Multiplier: For new solar electric systems installed and operating prior to December 31, 2003, Load-Serving Entities would qualify for multiple extra credits for kWh produced for five years following operational start up of the solar electric system. The five year extra credit would vary depending upon the year in which the system started up, as follows:~~
- | <del>YEAR</del> | <del>EXTRA CREDIT MULTIPLIER</del> |
|-----------------|------------------------------------|
| <del>1997</del> | <del>.5</del>                      |
| <del>1998</del> | <del>.5</del>                      |
| <del>1999</del> | <del>.5</del>                      |
| <del>2000</del> | <del>.4</del>                      |
| <del>2001</del> | <del>.3</del>                      |
| <del>2002</del> | <del>.2</del>                      |
| <del>2003</del> | <del>.1</del>                      |
- ~~Eligibility to qualify for the Early Installation Extra Credit Multiplier would end in 2003. However, any eligible system that was operational in 2003 or before would still be allowed the applicable extra credit for the full five years after operational start up.~~
2. ~~Solar Economic Development Extra Credit Multipliers: There are two equal parts to this multiplier, an in-state installation credit and an in-state content multiplier.~~
- a. ~~In State Power Plant Installation Extra Credit Multiplier: Solar electric power plants installed in Arizona shall receive a .5 extra credit multiplier.~~

- ~~b. In-State Manufacturing and Installation Content Extra Credit Multiplier: Solar electric power plants shall receive up to a .5 extra credit multiplier related to the manufacturing and installation content that comes from Arizona. The percentage of Arizona content of the total installed plant cost shall be multiplied by .5 to determine the appropriate extra credit multiplier. So, for instance, if a solar installation included 80% Arizona content, the resulting extra credit multiplier would be .4 (which is .8 X .5).~~
- ~~3. Distributed Solar Electric Generator and Solar Incentive Program Extra Credit Multiplier: Any distributed solar electric generator that meets more than one of the eligibility conditions will be limited to only one .5 extra credit multiplier from this subsection. Appropriate meters will be attached to each solar electric generator and read at least once annually to verify solar performance.~~
- ~~a. Solar electric generators installed at or on the customer premises in Arizona. Eligible customer premises locations will include both grid connected and remote, non grid-connected locations. In order for Load-Serving Entities to claim an extra credit multiplier, the Load-Serving Entity must have contributed at least 10% of the total installed cost or have financed at least 80% of the total installed cost.~~
- ~~b. Solar electric generators located in Arizona that are included in any Load Serving Entity's Green Pricing program.~~
- ~~c. Solar electric generators located in Arizona that are included in any Load-Serving Entity's Net Metering or Net Billing program.~~
- ~~d. Solar electric generators located in Arizona that are included in any Load-Serving Entity's solar leasing program.~~
- ~~e. All Green Pricing, Net Metering, Net Billing, and Solar Leasing programs must have been reviewed and approved by the Director, Utilities Division in order for the Load-Serving Entity to accrue extra credit multipliers from this subsection.~~
- ~~4. All multipliers are additive, allowing a maximum combined extra credit multiplier of 2.0 in years 1997-2003, for equipment installed and manufactured in Arizona and either installed at customer premises or participating in approved solar incentive programs. So, if a Load-Serving Entity qualifies for a 2.0 extra credit multiplier and it produces 1 solar kWh, the Load-Serving Entity would get credit for 3 solar kWh (1 produced plus 2 extra credit).~~
- D. Load-Serving Entities selling electricity under the provisions of this Article shall provide reports on sales and portfolio power as required in this Article, clearly demonstrating the output of**

~~portfolio resources, the installation date of portfolio resources, and the transmission of energy from those portfolio resources to Arizona consumers. The Commission may conduct necessary monitoring to ensure the accuracy of these data. Reports shall be made according to the Reporting Schedule in R14-2-1613(B).~~

- ~~E. Photovoltaic or solar thermal electric resources that are located on the consumer's premises shall count toward the Environmental Portfolio Standard applicable to the current Load-Serving Entity serving that consumer unless a different Load-Serving Entity is entitled to receive credit for such resources under the provisions of R14-2-1618(C)(3)(a).~~
- ~~F. Any solar electric generators installed by an Affected Utility to meet the environmental portfolio standard shall be counted toward meeting renewable resource goals for Affected Utilities established in Decision No. 58643.~~
- ~~G. Any Load-Serving Entity that produces or purchases any eligible kWh in excess of its annual portfolio requirements may save or bank those excess kWh for use or sale in future years. Any eligible kWh produced subject to this rule may be sold or traded to any Load-Serving Entity that is subject to this rule. Appropriate documentation, subject to Commission review, shall be given to the purchasing entity and shall be referenced in the reports of the Load-Serving Entity that is using the purchased kWh to meet its portfolio requirements.~~
- ~~H. Environmental Portfolio Standard requirements shall be calculated on an annual basis, based upon electricity sold during the calendar year.~~
- ~~I. A Load-Serving Entity shall be entitled to receive a partial credit against the portfolio requirement if the Load-Serving Entity or its affiliate owns or makes a significant investment in any solar electric manufacturing plant that is located in Arizona. The credit will be equal to the amount of the nameplate capacity of the solar electric generators produced in Arizona and sold in a calendar year times 2,190 hours (approximating a 25% capacity factor).~~
  - ~~1. The credit against the portfolio requirement shall be limited to the following percentages of the total portfolio requirement:  
2001: Maximum of 50% of the portfolio requirement  
2002: Maximum of 25% of the portfolio requirement  
2003 and on: Maximum of 20% of the portfolio requirement~~
  - ~~2. No extra credit multipliers will be allowed for this credit. In order to avoid double-counting of the same equipment, solar electric generators that are used by other Load-Serving Entities~~

~~to meet their Arizona portfolio requirements will not be allowable for credits under this Section for the manufacturer/Electric Service Provider to meet its portfolio requirements.~~

- ~~J. The Director, Utilities Division shall develop appropriate safety, durability, reliability, and performance standards necessary for solar generating equipment and environmentally friendly renewable electricity technologies and to qualify for the portfolio standard. Standards requirements will apply only to facilities constructed or acquired after the standards are publicly issued.~~
- ~~K. A Load-Serving Entity shall be entitled to meet up to 20% of the portfolio requirement with solar water heating systems or solar air conditioning systems purchased by the Load-Serving Entity for use by its customers, or purchased by its customers and paid for by the Load-Serving Entity through bill credits or other similar mechanisms. The solar water heaters must replace or supplement the use of electric water heaters for residential, commercial, or industrial water heating purposes. For the purposes of this rule, solar water heaters will be credited with 1 kWh of electricity produced for each 3,415 British Thermal Units of heat produced by the solar water heater and solar air conditioners shall be credited with kWhs equivalent to those needed to produce a comparable cooling load reduction. Solar water heating systems and solar air conditioning systems shall be eligible for Early Installation Extra Credit Multipliers as defined in R14-2-1618(C)(1) and Solar Economic Development Extra Credit Multipliers as defined in R14-2-1618(C)(2)(b).~~
- ~~L. A Load-Serving Entity shall be entitled to meet the portfolio requirement with electricity produced in Arizona by environmentally-friendly renewable electricity technologies that are defined as in-state landfill gas generators, wind generators, and biomass generators, consistent with the phase-in schedule in R14-2-1618(B)(3). Systems using such technologies shall be eligible for Early Installation Extra Credit Multipliers as defined in R14-2-1618(C)(1) and Solar Economic Development Extra Credit Multipliers as defined in R14-2-1618(C)(2)(b).~~