Title 4--DEPARTMENT OF
ECONOMIC DEVELOPMENT
Division 240--Public Service
Commission
Chapter 22--Electric Utility Resource Planning

4 CSR 240-22.050 Demand-Side Resource Analysis
PURPOSE: This rule specifies the methods by which end-use measures and demand-side programs shall be developed and screened for cost-effectiveness. It also requires the ongoing evaluation of end-use measures and programs, and the use of program evaluation information to improve program design and cost-effectiveness analysis.
(MEDA: didn’t see any of waiver request reflected here. Consider going to Top-down approach.)(UE: Start with programs. Fine tune measures. Look at DS as a marketing problem. Dual path. If DSM potential study (comprehensive across customers and end-uses with statistical rigor, end-use measure identification, customer decision modeling that gives understanding of what & why customers are making decisions) exists, then top-down updated for significant changes; if no potential study exists then do a bottom up analysis. Process needs to be more market driven. Top-down needs to have good handle on customers and how they use energy. More time on marketing less time on load shapes)(OPC: skeptical because we haven’t seen a potential study. Once data base has been developed not as much work for subsequent filings. Keep current structure.)(KCPL: in time you have data base. Value to both methods. Allow both.)(EDE: has used top-down approach. Special case since they have a collaborative. Have used consultants. Would have to do waivers again.)(KCPL: avoided cost has changed to market base.)(UE: Need a good assessment of long-term market prices – both energy and capacity avoided cost. MISO doesn’t currently have these long-term costs.)

(1) Identification of End-Use Measures. The analysis of demand-side resources shall begin with the development of a menu of energy efficiency and energy management, including demand response, end-use measures. (DNR: the menu shall be sufficiently comprehensive to support the development of maximum achievable potential DS resources. Need definition of maximum achievable potential.)(UE & KCPL: what does “sufficiently comprehensive” mean? Does it mean every possible end-use? Pre-review of end-use measure list from stakeholders?)(KCPL: cost issue of acquiring data)(DNR: not every possible just the ones that are reasonable to persue.)(Johnstone: challenge tendency to define potential and ask utilities to spend $ to reach that point. Utilities may not be able to implement what is best for the state. May be more cost-effective approaches (building codes and efficiency standards) for the state than utility implementation.) (McKinnie: narrow down based on “big energy savers”? Look at forecast drivers?)(DNR: what is the objective of developing menu?)The menu shall classify potential end use measures as devices, technologies, rate structures or operating procedures pursuant to 4 CSR 240-22.020 (17) and (18). The utility shall explicitly consider the role of the Smart Grid on enhanced deliverability of energy efficiency and energy management end-use measures pursuant to 4 CSR 240-22.045 (4). The menu of energy efficiency and energy management end-use measures shall ~~that~~ provide broad coverage of:~~-~~ (UE:key definitions from SB 376 demand response, DS program. Demand response could incorporate rate structures. Broader definition of energy efficiency.)
(A) All major customer classes and subclasses as identified in 4 CSR 240-22.030 (2) (A), including at least residential, commercial, industrial and interruptible and other rate or cost-of-service classes;
(B) All significant decision-makers, including at least those who choose building design features and thermal integrity levels, equipment and appliance efficiency levels, and utilization levels of the energy-using capital stock;

(C) All major end uses, including at least lighting, refrigeration, space cooling, space heating, water heating and motive power; and
(D) Renewable energy sources and energy technologies that substitute for electricity at the point of use, including customer generated renewable energy resources pursuant to 4 CSR 240-20.XXX (1) (F)to comply with the renewable energy standard.

(2) Calculation of Avoided Costs. The utility shall develop estimates of the cost savings that can be obtained by substituting demand-side resources for existing and new supply-side resources. These avoided cost estimates, expressed in nominal dollars, shall be used for cost-effectiveness screening and ranking of end-use measures and demand-side programs.
(UE: market based approach for energy. Cost of CT for avoided capacity cost. Flexibility in rules to do either if shown to be reasonable. Could come up with annual and seasonal number. Hourly price wasn't used for screening. Make less prescriptive – put in goal.)
(EDE: Midas hourly costs of plan without DS. hourly market Midas prices from Northern SPP interconnect. Prefers flexible approach.)
(KCPL: uses DSMore. Annualized summary and PV of annual. Per participant savings per month. Includes avoided costs for transmission and distribution. Avoided costs are inputs and outputs estimated using "fundamental" model of Eastern Interconnect to get market clearing price. Energy avoided costs are "market clearing price" output from Midas. Prescriptive would keep us locked into old method.)
(DNR: would like to know what avoided costs are being used. Reporting requirements could require time period avoided costs. Check to see what other states are using.)
(Maurice: would like to understand models and have access to input and outputs. Don't need to be able to run model just review for reasonableness. If goal is set, it needs to be clearly stated in rule and documented by utility)
(OPC: agrees with Maurice. Need to know how avoided costs are calculated. Concern with how to get annual capacity costs to hours. Possibly use capacity factor methodology (such as UE uses) or allocated based on LOLP. Need to match up with RTO resource adequacy requirements. Require that avoided be reasonable with guidance to what reasonable approach is. Don't require certain model. Goal: energy prices be able to put in buckets. Long term avoided capacity cost realistic with current resources and current resource plan.)
(McKinnie: wants full description of how capacity values are developed.)
(A) Supply Resource Cost Estimates. The utility shall use the cost estimates developed pursuant to 4 CSR 240-22.040(2) to calculate the following two (2) estimates of avoided cost: avoided utility costs and avoided utility costs plus avoided probable environmental costs.
1. The choice of new generation options used to calculate avoided costs shall be limited to those which will meet the need for capacity under the base-case load forecast at approximately the lowest present value of utility revenue requirements over the planning horizon. The utility shall document the basis on which the timing and choice of the new generation options were determined to be approximately least cost.
2. The utility shall calculate the annual capacity cost of each new generation option and new transmission and distribution facilities as the sum of the levelized capital cost per kilowatt-year and the fixed operation and maintenance cost per kilowatt-year.
3. The utility shall calculate the direct running cost of each generation option as the sum of fuel costs, ~~sulfur dioxide~~ emission allowance costs, and variable operation and maintenance costs per kilowatt-hour (kWh). The probable environmental costs calculated pursuant to 4 CSR 240-22.040(2)(B) shall also be

expressed on a per-kilowatt hour basis for both existing and new generation resources.

(B) Avoided Cost Periods. The utility shall determine avoided cost periods by grouping hours on a seasonal (for example, summer, winter and transition) and time-of-use basis (for example, on-peak, off-peak, super-peak or shoulder-peak) as required to adequately reflect significant differences in running costs and the type of capacity being utilized to maintain required reserve margins.

(C) Calculation of Avoided Capacity and Running Costs. Avoided costs shall be calculated as the difference in costs associated with a specified decrement in load large enough to delay the on-line date of the new capacity additions by at least one (1) year.

1. Avoided running cost. For each year of the planning horizon and for each avoided cost period, the utility shall calculate the avoided direct running cost per kWh (including ~~sulfur dioxide~~ emission allowance costs) and the avoided probable environmental running cost per kWh due to the specified load decrement.

2. Avoided capacity costs. The utility shall calculate and document the avoided capacity costs per kilowatt-year for each year of the planning horizon.

A. This calculation shall include the costs of any new generation, transmission and distribution facilities that are delayed or avoided because of the specified load decrement.

B. For each year of the planning horizon, the utility shall determine the avoided cost periods in which the avoided new generation, transmission and distribution capacity was utilized, and shall allocate a nonzero portion of the annualized avoided capacity costs to each of the periods in which that capacity was utilized.

(D) Avoided Demand and Energy Costs. The utility shall use the avoided capacity and running costs (appropriately adjusted to reflect reliability reserve margins, demand losses and energy losses) to calculate the avoided demand and energy costs for each avoided cost period. Demand periods shall be defined as the avoided cost periods in which there is a significant probability of a loss of load (for example, periods which require the use of peaking capacity to maintain power pool reserve margins). Nondemand periods are the avoided cost periods in which there is not a significant probability of a loss of load.

1. Demand period avoided demand costs. Avoided demand costs per kilowatt-year for the demand periods of each season shall include avoided transmission and distribution capacity costs, plus the smaller of the avoided generation capacity cost allocated to the demand period or the avoided capacity cost of peaking capacity.

2. Demand period avoided energy costs. Any capacity cost per kilowatt-year allocated to the demand periods but not included in the avoided demand cost shall be converted to an avoided energy cost by dividing the avoided capacity cost per kilowatt-year by the number of hours in the associated demand period. The utility shall add this converted avoided capacity cost to both of the running cost estimates developed pursuant to paragraph (2)(C)1. to calculate the demand period direct energy costs and the probable environmental energy costs.

3. Nondemand period avoided demand cost. The avoided demand cost for the nondemand periods is zero (0).

4. Nondemand period avoided energy costs. Avoided capacity cost per kilowatt-year allocated to the nondemand periods within each season shall be converted to a per-kilowatt-hour cost by dividing the avoided capacity cost per kilowatt-year by the number of hours in the associated nondemand period. The utility shall add this converted avoided capacity cost to both of the running cost estimates developed pursuant to paragraph (2)(C)1. to calculate the nondemand period direct energy costs and the probable environmental energy costs.

5. Annual avoided demand and energy costs. Annual avoided demand costs shall include avoided transmission and distribution capacity costs, plus the smaller of the annual avoided generation capacity costs or the avoided capacity cost of

peaking capacity. Annual avoided energy costs shall include annual avoided running costs plus any avoided capacity costs not included in the annual demand cost.

(3) Cost-Effectiveness Screening of End-Use Measures. The utility shall evaluate the cost-effectiveness of each end-use measure identified pursuant to section (1) using the probable environmental benefits test. The utility shall explicitly consider the role of the Smart Grid on increasing the benefit and/or reducing the cost of implementing or using end-use measures, and document its analysis. (UE: what does "consider the role of the Smart Grid" mean? Creates circular issue.) (Johnstone: some smart grid technologies have already been implemented by large customers. Smart grid is wider availability of these same technologies.) (KCPL: smart grid would be sunk cost, cost-effectiveness should be based on marginal cost of implementation)(technology at customer level that allows customer to respond) All costs and benefits shall be expressed in nominal dollars. Proposed Definition: A measure or rate structure enabled by communication technology on customer or utility side of the meter or by the meter itself that reduces demand at the generation, transmission, distribution or customer level of the system. Another definition: use federal definitions that fit resource planning.(UE: Smart grid used to break down barriers to implementation of energy efficiency and demand response.)

(A) The utility shall develop estimates, by ~~of the~~ end-use measure, of the demand reduction ~~for each demand period~~ and energy savings per installation for each avoided cost period on a normal-weather basis for the most probable future scenario with and without Smart Grid upgrades. Initial estimates of demand and energy impacts shall be based on the best available (UE: what does best available mean?)(OPC: Commission determination)information from in-house research, vendors, consultants, industry research groups, national laboratories and other credible sources. (OPC: not clear where post-initial comes from. Need some language to clarify 7(A)(3).)If the utility can show that subannual load impact estimates are not required to capture the potential benefits of an end-use measure, annual estimates of demand and energy savings may be used for cost-effectiveness screening.

(B) Benefits per installation of each end-use measure in each avoided cost period shall be calculated as the demand reduction multiplied by the levelized avoided demand cost plus the energy savings multiplied by the levelized avoided energy cost.

1. Avoided costs in each avoided cost period shall be levelized over the planning horizon using the utility discount rate.

2. Annualized benefits shall be calculated as the sum of the levelized benefits over all avoided cost periods.

(C) Annualized costs per installation for each end-use measure shall be calculated as the sum of the following components:

1. Incremental costs of implementing the measure (regardless of who pays these costs) levelized over the life of the measure using the utility discount rate;

2. Incremental annual operation and maintenance costs (regardless of who pays these costs) levelized over the life of the measure using the utility discount rate; and

3. Any probable environmental impact mitigation costs due to implementation of the end-use measure that are borne by either the utility or the customer.

(D) Annualized costs for end-use measures shall not include either utility marketing and delivery costs for demand-side programs or lost revenues due to measure-induced reductions in energy sales or billing demands between rate cases.

(E) Annualized benefits minus annualized costs per installation must be positive or the ratio of annualized benefits to annualized costs must be greater than one (1) for an end-use measure to pass the screening test. The utility may relax this criterion for measures that are judged to have potential benefits which are not captured by the estimated load impacts or avoided costs, such as the customer generated renewable energy resources intended to comply with the Renewable Energy Standard and programs designed to reduce the number of disconnects of low income customers. (Robertson: customer renewables should be SS resource)

(F) End-use measures that pass the probable environmental benefits test must be included in at least one (1) potential demand-side program, or the utility must explain and document why the measure was not included in a demand-side program.

(G) For each end-use measure that passes the probable environmental benefits test, the utility also shall perform the utility benefits test for informational purposes. This calculation shall include the cost components identified in paragraphs (3)(C)1. and 2.~~;~~

(4) The utility shall estimate the technical potential of each end-use measure that passes the screening test. (Comment: This is the equivalent of the economic potential of the end-use measures. Once program are designed and program costs are developed, the economic potential of each demand-side program will be estimated pursuant to 4 CSR 240-22.050 (7) (G).)(KCPL: doesn't agree that technical potential is same as economical potential. Change to economic potiential?)(DNR: technical potential of measures or programs? Maybe should be after (7).)

(5) The utility shall conduct market research studies, customer surveys, pilot demand-side programs, test marketing programs and other activities as necessary to estimate the technical potential of end-use measures and to develop the information necessary to design and implement cost-effective demand-side programs. These research activities shall be designed to provide a solid foundation of ~~utility-specific~~ information, applicable to the utility, about how and by whom energy-related decisions are made and about the most appropriate and cost-effective methods of influencing these decisions in favor of greater long-run energy efficiency and energy management impacts. The utility may compile existing data or adopt data developed by other entities, including government agencies and other utilities, as long as the utility verifies the applicability of the adopted data to its service territory.

(6) The utility shall develop a set of potential demand-side programs that are designed to deliver an appropriate selection of end-use measures to each market segment. The demand-side program planning and design process shall include at least the following activities and elements: (OPC: Utility shall develop a moderate and an aggressive set of demand-side programs.)(DNR: do analysis on moderate and aggressive programs as part of portfolio analysis.)(OPC: may fit better in (7))(KCPL: appropriate for energy programs. Does it work as well for capacity reduction programs?)

(A) Review of successful demand-side programs that have been implemented by other utilities with similar electric prices and customer makeup to determine if similar programs would also be successful for the utility;(DNR: Review commonly used program designs)

(B) Identify market segments that are numerous and diverse enough to provide relatively complete coverage of the classes and decision-makers identified in subsections (1)(A) and (B), and that are specifically defined to reflect the primary market imperfections that are common to the members of the market segment;

(C~~B~~) Analyze the interactions between end-use measures (for example, more efficient lighting reduces the savings related to efficiency gains in cooling equipment because efficient lighting reduces intrinsic heat gain). (Comment: The purpose is to adjust the stand alone end-use measure impact estimates for interactions that would occur if bundled with other end-use measures in a program so that program cost effectiveness can be estimated.);

(D~~C~~) Assemble menus of end-use measures that are appropriate to the shared characteristics of each market segment and cost-effective as measured by the screening test; and

(E~~D~~) Design a marketing plan and delivery process to present the menu of end-use measures to the members of each market segment and to persuade decision-makers to implement as many of these measures as may be appropriate to their situation.

(F) Explicitly assess the role of the Smart Grid on increasing the benefit and/or reducing the cost of implementing or using end-use measures.

(7) Cost-Effectiveness Screening of Demand-Side Programs. The utility shall evaluate the cost-effectiveness of each potential demand-side program developed pursuant to section (6) using the total resource cost test. The utility cost test shall also be performed for purposes of comparison. <Brubaker – add RIM and Participant Cost test – would also need to be added to the reporting requirements at the end of the section> <would these tests be over the life of the program? All twenty years? If so, what's the basis of the rate? Rate trajectory already in rule? KCPL: Doing the RIM test would be a lot of work after the preferred plan has been determined on plans that weren't picked. If on par, do for all supply side options too?> <Brubaker – pretty standard in CA to calculate the rate impact of implementing DSM. May not make choices based on RIM. May be other ways of determining what the rate impacts are, not looking to burden.> All costs and benefits shall be expressed in nominal dollars. The following procedure shall be used to perform these tests:

(A) The utility shall estimate the incremental and cumulative number of program participants and end-use measure installations due to the program and the incremental and cumulative demand reduction and energy savings due to the program in each avoided cost period in each year of the planning horizon.

1. Initial estimates of demand-side program load impacts shall be based on the best available information about program participation rates and load impacts from in-house research, vendors, consultants, industry research groups, national laboratories or other credible sources.

2. This estimation shall include analysis of interactions from 4 CSR 240-22.050(6) (C).

3. As the load-impact measurements required by subsection (9) (C~~B~~) become available, these results shall be used in the ongoing development and screening of demand-side programs and in the development of alternative resource plans;

(B) The utility shall estimate the cost of administering each demand-side program. (Comment: The program administration cost would be added to the measure cost, adjusted for interactivity between end use measures, to calculate the total program cost.)

(C) In each year of the planning horizon, the benefits of each demand-side program shall be calculated as the cumulative demand reduction multiplied by the avoided demand cost plus the cumulative energy savings multiplied by the avoided energy cost, summed over the avoided cost periods within each year. These calculations shall be performed using the avoided probable environmental costs developed pursuant to section (2);

(D~~C~~) Utility Cost Test. In each year of the planning horizon, the costs of each demand-side program shall be calculated as the sum of all utility incentive payments plus utility costs to administer, deliver and evaluate each demand-side program. The utility shall explicitly consider and document the role of the Smart Grid on increasing the benefit and/or reducing the cost of demand side programs. For purposes of this test, demand-side program costs shall not include lost revenues or costs paid by participants in demand-side programs;

(E~~D~~) Total Resource Cost Test. In each year of the planning horizon, the costs of each demand-side program shall be calculated as the sum of all incremental costs of end-use measures that are implemented due to the program (including both utility and participant contributions) plus utility costs to administer, deliver and evaluate each demand-side program. The utility shall explicitly consider and document the role of the Smart Grid on increasing the benefit and/or reducing the cost of demand side programs. For purposes of this test, demand-side program costs shall not include lost revenues or utility incentive payments to customers;

(F~~E~~) The present value of program benefits minus the present value of program costs over the planning horizon must be positive or the ratio of annualized benefits to annualized costs must be greater than one (1) for a demand-side program to pass the utility cost test or the total resource cost test. The utility may relax this criterion for programs that are judged to have potential benefits that are not captured by the estimated load impacts or avoided costs, such as programs designed to encourage customer installation of customer generated renewable energy resources to comply with the Renewable Energy Standard and programs designed to reduce the number of disconnects of low income customers;~~ and~~ <KCPL: RES says to compute the cost of these programs separately – is putting those costs here hiding them from the other rule?>

(F) Potential demand-side programs that pass the total resource cost test shall be considered as candidate resource options and must be included in at least one (1) alternative resource plan developed pursuant to 4 CSR 240-22.060(3). The utility shall include as candidate resource options programs designed to encourage customer installation of customer generated renewable energy resources to comply with the Renewable Energy Standard as required by 4 CSR 240-22.XXX (2) KCPL – see comment in previous paragraph as well, plus where does RES say to encourage customer installation? May need to be reworded.> <Note that there are two (2) "F" sections here> <KCPL: obligated to pay per watt for solar behind the meter, so doing the test is meaningless – wouldn't that put a negative cost draw on the rest of the portfolio? Put that cost driver in a separate part of the portfolio / planning process> <OPC: screening each program individually in 050(7). Could say providing incentives for customer installations.> ; and

(DNR: (F.V) The utility shall develop at least two demand side portfolios pursuant to 4 CSR 240-22.020(XX), one of which shall represent the maximum potential impact on customer energy demand achievable through implementation of demand-side programs in the utility's service territory;) (DNR-demand side portfolio would be defined> <Henry – RES requires an IRP style planning exercise, and the customer generation needs to be treated as a supply side resource – avoided a bunch of this discussion> <Gaw – how the mix impacts rates is in the RES rulemaking. If on customer side of the meter, demand side resource; how deal with non renewable customer resources? If that's a demand side resource, then how is renewable different? Either have to assume cost analysis was done w/in the RES, or write this portion that contends with the cost impact provisioning.>

(G) The utility shall estimate the maximum and realistic achievable potential of each program passing the total resource cost test, and each portfolio developed pursuant to paragraph F.V.~~.~~ <need defs of MAP and RAP>

<AUE: level of prescription would increase through the DNR suggestions. Really don't currently have MAP and RAP per program, just for the whole portfolio.>

(8) For each demand-side program that passes the total resource cost test, the utility shall develop time-differentiated load impact estimates over the

planning horizon at the level of detail required by the supply system simulation model that is used in the integrated resource analysis required by 4 CSR 240-22.060(4).

(9) Evaluation of Demand-Side Programs. The utility shall develop evaluation plans for all demand-side programs that are included in the preferred resource plan selected pursuant to 4 CSR 240-22.070(6). The purpose of these evaluations shall be to develop the information necessary to improve the design of existing and future demand-side programs, and to gather data on the implementation costs and load impacts of programs for use in cost-effectiveness screening and integrated resource analysis.

<AUE: process of bringing evaluator in up front, but not during the planning process. Since they know it will change when they hire an implementation contractor, not worth the resources at this stage. Have requested waivers in past, and expect to do so in future if it stays like this.> <DNR – appropriate time for evaluation plan filing may be tariff approval> <OPC – promotional practice rule for evaluation plans (for pilot programs only)> <OPC also wants that high level evaluation plan in addition to the language out of the promotional practice rule in terms of timelines of evaluation plan readiness concurrent with tariff filing> <DNR – guidelines for the evaluation plans in current rule good, want to change timing plus filing of high level plan>

(A) Process Evaluation. Each demand-side program that is part of the utility's preferred resource plan shall be subjected to an ongoing evaluation process which addresses at least the following questions about program design:

1. What are the primary market imperfections that are common to the target market segment?

2. Is the target market segment appropriately defined or should it be further subdivided or merged with other segments?

3. Does the mix of end-use measures included in the program appropriately reflect the diversity of end-use energy service needs and existing end-use technologies within the target segment?

4. Are the communication channels and delivery mechanisms appropriate for the target segment? and

5. What can be done to more effectively overcome the identified market imperfections and to increase the rate of customer acceptance and implementation of each end-use measure included in the program?

(B) Impact Evaluation. The utility shall develop methods of estimating the actual load impacts of each demand-side program included in the utility's preferred resource plan to a reasonable degree of accuracy.

1. Impact evaluation methods. Comparisons of one (1) or both of the following types shall be used to measure program impacts in a manner that is based on sound statistical principles:

A. Comparisons of preadoption and postadoption loads of program participants, corrected for the effects of weather and other intertemporal differences; and

B. Comparisons between program participants' loads and those of an appropriate control group over the same time period.

2. When evaluating market transformation programs, the utility shall consider the entire market to be the program participant. <AUE – whole value chain in mkt transformation programs – why just market transformation programs> <KCPL: consider some language to tighten it up, because market is the entire delivery chain> <DNR – when evaluating market transformation programs, utility shall use best practices of evaluation>.

3. The utility shall develop load-impact measurement protocols that are designed to make the most cost-effective use of the following types of measurements, either individually or in combination: monthly billing data, load research data, end-use load metered data, building and equipment simulation models, and survey responses or audit data on appliance and equipment type, size

and efficiency levels, household or business characteristics, or energy-related building characteristics.
_(C) The utility shall develop protocols to collect data regarding demand-side program market potential, participation rates, utility costs, participant costs and total costs. <OPC – keep this even if changing timing of evaluation plan filing – sees this as a reporting requirement>

(10) Demand-side programs and load-building programs shall be separately designed and administered, and all costs shall be separately classified so as to permit a clear distinction between demand-side program costs and the costs of load-building programs. The costs of demand-side resource development that also serve other functions shall be allocated between the functions served.

(11) Reporting Requirements. To demonstrate compliance with the provisions of this rule, and pursuant to the requirements of 4 CSR 240-22.080, the utility shall prepare a report that contains at least the following information:
_(A) A list of the end-use measures developed for initial screening pursuant to the requirements of section (1) of this rule;
_(B) The estimated load impacts, annualized costs per installation and the results of the probable environmental benefits test for each end-use measure identified pursuant to section (1). The report shall explicitly assess the role of the Smart Grid on increasing the benefit and/or reducing the cost of end use measures. The utility report shall document the utility's determination regarding the appropriate level of investment in the Smart Grid in relation to the associated increase in opportunity for demand-side programs;
_(C) The technical potential and the results of the utility benefits test for each end-use measure that passes the probable environmental benefits test;
_(D) Documentation of the methods and assumptions used to develop the avoided cost estimates developed pursuant to section (2) including:
__1. A description of the type and timing of new supply resources, including transmission and distribution facilities, used to calculate avoided capacity costs;
__2. A description of the assumptions and procedure used to calculate avoided running costs;
__3. A description of the avoided cost periods and how they were determined;
__4. A tabulation of the direct running costs and the probable environmental running costs for each avoided cost period in each year of the planning horizon; and
__5. A tabulation of the avoided demand cost, the avoided direct energy costs and the avoided probable environmental energy costs for each avoided cost period in each year of the planning horizon;
  6. The utility discount rate used for the development of levelized avoided costs;
_(E) Copies of completed market research studies, pilot programs, test marketing programs and other studies as required by section (5) of this rule and descriptions of those studies that are planned or in progress and the scheduled completion dates;
_(F) A description of each market segment identified pursuant to subsection (6)(A);
_(G) A description of each demand-side program developed for initial screening pursuant to section (6) of this rule, including a list of all end use measures contained within each program;
_(H) A tabulation of the incremental and cumulative number of participants, load impacts, utility costs and program participant costs in each year of the planning horizon for each demand-side program developed pursuant to section (6) of this rule;

_(I) The results of the utility cost test and the total resource cost test for each demand-side program, with a sensitivity showing the impact of proposed Smart Grid upgrades, developed pursuant to section (6) of this rule; and
_(J) A description of the process and impact evaluation plans for demand-side programs that are included in the preferred resource plan as required by section (9) of this rule and the results of any such evaluations that have been completed since the utility's last scheduled filing pursuant to 4 CSR 240-22.080.
AUTHORITY: sections 386.040, 386.610 and 393.140, RSMo 1986 and 386.250, RSMo Supp. 1991.* Original rule filed June 12, 1992, effective May 6, 1993.
*Original authority: 386.040, RSMo 1939; 386.250, RSMo 1939, amended 1963, 1967, 1977, 1980, 1987, 1988, 1991; 386.610, RSMo 1939; and 393.140, RSMo 1939, amended 1949, 1967.