STATE OF ILLINOIS

ILLINOIS COMMERCE COMMISSION

ILLINOIS POWER COMPANY	**)**	
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Proposed revisions to delivery services	**)**	**01-0432**
Tariff sheets and other sheets.	**)**	

ILLINOIS POWER COMPANY'S REPLY BRIEF (REDACTED)

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I. INTRODUCTION

Illinois Power Company ("Illinois Power", "IP" or "Company") is responding to the initial briefs filed by the Staff of the Commission ("Staff"), the Illinois Industrial Energy Consumers ("IIEC"), the Citizens Utility Board and the Attorney General ("CUB/AG"), and MidAmerican Energy Company ("MEC"). None of the arguments advanced by Staff, IIEC, CUB/AG or MEC in opposition to Illinois Power's proposals should persuade the Commission to reject any of IP's proposals or to adopt the contrary positions of the other parties. For the reasons set forth in IP's Initial Brief and in this Reply Brief, the Commission should adopt Illinois Power's proposed rate base and operating expense statement, along with the agreed rate of return, as well as the Company's proposed rate design and other terms and conditions for its delivery services tariffs ("DST").

II. REVENUE REQUIREMENTS

A. Test Year

Staff's Initial Brief, at page 3, contains two references to the use of a "1999 historical test year" in this case. Illinois Power assumes this is a mistake, as all presentations in this case have been based on a 2000 test year. No party has objected to the use of the 2000 test year. Staff also refers to "known and measurable adjustments through June 30, 2001." In fact, some of the adjustments in this case, including adjustments agreed to by Staff, reflect information later than June 30, 2001. Although Staff contests a number of IP's proposed adjustments (as discussed individually in the remainder of this brief), Staff has not objected to any adjustment on the grounds that it is based on information subsequent to June 30, 2001.

B. Distribution Rate Base

1. Overview of IP's Proposed Distribution Rate Base

Illinois Power continues to propose the same distribution rate base that is summarized in §II.B.1 of its Initial Brief and detailed in Rev. IP Exhibit 3.24.

2. Uncontested Adjustments to Rate Base

This section only addresses, as necessary, certain comments in Staff's Initial Brief concerning uncontested adjustments to distribution rate base. Except as discussed in this section, no party has raised any issues concerning any of the uncontested adjustments to rate base listed in §II.B.2 of Illinois Power's Initial Brief.

Cash working capital. IP agrees with Staff that the final cash working adjustment needs to reflect the impact of other revenue requirement components that affect the calculation of cash working capital.

Pro forma plant additions. Although Illinois Power and Staff agree conceptually on the basis for pro forma plant additions (see IP Init. Br., §II.B.3.a), IP has addressed this adjustment under "Contested Adjustments" in §II.B.3.a of its Initial Brief and this Reply Brief, because CUB/AG are not in agreement with IP and Staff. As discussed in §II.B.3.a of IP's Initial Brief, Staff witness Mary Everson agreed with the Company's surrebuttal presentation that the capital additions should consist of actual expenditures through September 30, 2001, and remaining expenditures as of that date, on projects that had received funding approval from management as of September 30, 2001. However, based on the record citations in §I.B.1.a of, and examination of Appendix A to, Staff's Initial Brief, it is unclear whether Staff has referenced the correct values for capital additions. The correct values for this adjustment are shown on Rev. IP Exhibit 3.24, page 1, columns (3) and (4).

3. Contested Adjustments to Rate Base

a. Post Test-Year Capital Additions

As described in §II.B.3.a of Illinois Power's Initial Brief, the Company accepted Staff witness Mary Everson's limitation on post-test year capital additions to those projects that have received funding approval from management through IP's internal processes and procedures, which she concluded satisfied the "known and measurable" criterion. In accordance with this criterion, IP limited the capital additions to those projects that had received funding approval by September 30, 2001; this enabled the supporting information to be reviewed by Ms. Everson prior to the close of the record in this case. (See Tr. 122-24)

CUB/AG, however, contend that post-test year capital additions should be limited to June 30, 2001. (CUB/AG Init. Br., pp. 6-11) Most of CUB/AG's arguments on this issue were addressed in §II.B.3.a of IP's Initial Brief. In evaluating CUB/AG's position on this issue, the Commission should keep in mind that in reaching her conclusions, Ms. Everson conducted a thorough review of IP's proposed capital additions, using established auditing and other standards as well as Commission precedent for determining what constitutes "known and measurable" post-test year capital additions that may be included in rate base where a historical test year is used. (See Staff Ex. 2.0, pp. 2-6 and §II.B.3.a of IP's Initial Brief) There is no evidence that CUB/AG's witness, Mr. Effron, conducted a similar review; rather, his position is premised on his thinly-disguised objection to any type of post-test year capital additions adjustment, a position that even he was forced to admit is contrary to this Commission's practices. (See GCI Ex. 2.0, p. 21) The Commission should also note that CUB/AG have not identified a single project in IP's proposed capital additions that CUB/AG contend does not in fact constitute "known and measurable" additions.

CUB/AG object to IP's adjustment for post-test year capital additions because a portion of the capital additions are being made to serve "new business" and, CUB/AG contend, IP is not recognizing growth in billing determinants beyond the test year. CUB/AG are wrong. In making this argument, CUB/AG cite to Mr. Effron's direct testimony, GCI Exhibit 2.0. (See CUB/AG Init. Br., pp. 7-9) However, in its rebuttal testimony, IP accepted an adjustment to billing determinants, originally suggested by Mr. Effron, that resulted in the number of customers in the billing determinants being the average of actual year-end 2000 and forecasted year-end 2001 customers. The kWh sales used in the billing determinants were adjusted upwards correspondingly. This adjustment was made to the billing determinants for all customer classes. (IP Ex. 6.6, pp. 3-4; Tr. 403-04; see IP Init. Br., pp. 10-11) In effect, therefore, the billing determinants that IP is using for purposes of this case represent average 2001 values, and are fully consistent with the capital additions adjustment.[1]

CUB/AG also contend that IP's proposed post-test year capital additions include projects that will be placed in service too far beyond the end of the test year. (CUB/AG Init. Br., pp. 9-11) CUB/AG assert that IP's adjustment includes over $15 million in distribution plant projects whose in-service dates will be between September 30, 2001, and June 30, 2002. (Id., p. 9) To put this figure in context, however, IP's adjustment includes $77.6 million of actual expenditures as of September 30, 2001. (IP Ex. 2.18, p. 3) In the aggregate, over 83% of the amount of capital additions sponsored by IP witness Barud using

[1] As described in §II.B.3.b of IP's Initial Brief and §II.B.3.b of this Reply Brief, IP has also reflected in rate base accumulated depreciation and deferred tax reserves through September 30, 2001, on plant that was in service as of December 31, 2000, thereby satisfying the other prong of CUB/AG's "balanced approach" argument concerning post-test year capital additions.

the "funded projects" criterion consists of <u>actual expenditures</u> as of September 30, 2001. (IP Ex. 2.17, p. 3)

Noting that some of the funded projects will not be completed and placed in service till June 2002, or 18 months after the end of the test year, CUB/AG argue that IP should have proposed a forecasted test year in order to include in rate base projects with completion dates as late as June 2002. (CUB/AG Init. Br., p. 6) However, 83 Ill. Adm. Code 285.150(e), which sets forth criteria for post-test year capital additions where an historical test year is used in a general rate case, and which Ms. Everson used as one of the indicia of the "known and measurable" criterion, authorizes the inclusion in rate base of capital additions to be placed in service within 12 months following the filing of the proposed tariffs, which in this case would be June 2002.

CUB/AG also argue that Staff witness Ms. Everson ignored a "cutoff date for pro forma adjustments" in DST.160 (which Ms. Everson also relied on as a source for the "known and measurable" criterion). (CUB/AG Init. Br., pp. 10-11) However, CUB/AG's reliance on DST.160 supports IP's and Staff's position, not CUB/AG's position. Specifically, CUB/AG note that DST.160 limits post-test year adjustments to those that ". . . occurred during the selected test year or are reasonably certain to occur subsequent to the selected test year but prior to January 1, 2001." DST.160 and the related Minimum Information Requirements were developed in Docket 98-0454 to guide the electric utilities' initial DST rate case filings in 1999. IP and the other electric utilities were required by law to file those initial DST cases 210 days prior to the initial offering of delivery services (October 1, 1999), or by on or about March 1, 1999. (220 ILCS 5/16-108(a)) The "cutoff date" of January 1, 2001 was some <u>22 months</u> after the date that the initial DST cases were required to be filed. Further, given that a 1997 test year was used in the 1999 DST Case, the "cutoff date" of January 1, 2001 in DST.160 was 36 months after the end of the historical test year. In summary, based on the use of a 2000 test year and the June 1, 2001 filing date in this case, the "cutoff date" of June 30, 2002 is within the parameters established by both 83 Ill. Adm. Code and DST.160 for post-test year adjustments to an historical test year.

CUB/AG's proposed limitation on post-test year capital additions to June 30, 2002, and their objections to the Company's proposed post-test year capital additions, should be rejected. IP's proposed capital additions, which conform to the standards applied by Staff, should be included in distribution rate base.

b. Accumulated Depreciation on Plant in Service at December 31, 2000

Illinois Power has adjusted (reduced) rate base by including accumulated depreciation and accumulated deferred taxes on plant in service as of December 31, 2000, for the period January 1, 2001 through September 30, 2001. This adjustment is consistent with the use of funded projects as of September 30, 2001 as the basis for capital additions.[2] (See IP Init. Br., §II.B.3.b) CUB/AG contend that because some of the capital additions projects will be placed in service between September 30, 2001 and June 30, 2002, rate base should be adjusted for the accumulated depreciation through June 30, 2002, on plant in service as of December 31, 2000. (CUB/AG Init. Br., pp. 11-12) However, CUB/AG's additional adjustment would be inconsistent with the capital additions adjustment. IP is not proposing (and Staff has not accepted) inclusion in rate base of all projected capital additions through June 30, 2002. If IP were to include in rate base all of its projected capital additions through

[2] In addition, IP has adjusted rate base for $12.54 million of retirements of plant that will be replaced by the capital additions. (See IP Ex. 2.18, p. 3, and IP Ex. 2.19)

June 2002, the amount of the adjustment to rate base would be considerably larger than what IP has in fact proposed (and Staff has accepted). (IP Ex. 2.17, p. 3) Further, IP's proposed capital additions consisted predominantly of <u>actual expenditures</u> as of September 30, 2001. (See IP Init. Br., §II.B.3.b) CUB/AG's additional adjustment to accumulated depreciation should be rejected.

c. General and Intangible Plant Included in Distribution Rate Base

Staff and IIEC contend that the amount of General & Intangible ("G&I") plant included in distribution rate base should be reduced.[3] (Staff Init. Br., §II.B.2.a; IIEC Init. Br., §I.B) IP addressed most of Staff's and IIEC's arguments in §II.B.3.c and §II.C.3.e of its Initial Brief. As shown in those sections, IP properly determined the amount of its G&I plant and A&G expense that should be included in distribution rate base and distribution operating expense, respectively, using labor expense allocation factors as required by the Commission in the 1999 DST Case. Staff's and IIEC's proposed adjustments are arbitrary; are based on the invalid premise that the Commission, in the 1999 DST Case, established a fixed and unchanging relationship between the amounts of G&I plant and distribution plant, and between the amount of A&G expense and distribution O&M, that must be maintained for all future cases; and would in effect require the Company to allocate G&I plant and A&G expense to a generation business it did not own in the test year, using generation labor it did not incur in the test year. Staff's and IIEC's proposals ignore the nature of common costs,

[3] Staff and IIEC each also propose an adjustment to the amount of A&G expense included in distribution operating expense, on essentially the same bases as their proposed adjustments to G&I plant in rate base. Both Staff and IIEC have presented their arguments for their proposed adjustments to G&I plant and to A&G expense together in the rate base sections of their Initial Briefs.

and fail to address the fundamental issue that it is unreasonable to expect that when one line of business is eliminated, the remaining lines of business can be provided using the same amount of common costs per dollar of direct costs as employed previously. Moreover, these parties provided no meaningful response to the Company's showing that its overall levels of G&I plant and electric A&G expense are reasonable. Accordingly, Staff's and IIEC's proposed adjustments must be rejected.

i. Staff's Arguments Do Not Support its Proposed Adjustment

Staff spends a considerable portion of the section of its Initial Brief on this issue arguing that IP is proposing to include substantially more G&I plant and A&G expense in rate base than in the 1999 DST Case, and demonstrating that Illinois Power did not allocate any G&I plant or A&G expense to "generation" in this case.[4] (See Staff Init. Br., pp. 6-13, 17) Whether or not IP allocated any G&I plant or A&G expense to "generation" in this case is not an issue; obviously, the Company did not allocate any G&I plant or A&G expense to "generation", because IP had no generation business, owned essentially no generation assets, and recorded essentially no generation labor in 2000, the test year in this case. IP also acknowledged that (particularly since its total G&I plant increased by only 3.7% from 1997 to 2000, and its electric A&G expenses decreased by 3% over the same period and by 17.4% from 1999 to 2000, see IP Init. Br., pp. 27, 65) the reason for the higher amount of G&I plant in rate base and A&G expenses in operating expense in this case in comparison to the 1999 DST case is that in 1997 (the test year in the 1999 DST Case) IP still owned generation and

[4] Staff misstates the amount of A&G expense that IP is proposing to include in distribution operating expense. Staff states that IP is proposing to include $47.14 million of A&G expense in distribution operating expense. (Staff Init. Br., p. 9) In fact, IP is proposing to include $41,682,000 of A&G expense in distribution operating expense. (Rev. IP Ex. 3.24, p. 3, col. (36), line 22)

had generation labor expense, while in 2000 it did not. Therefore, in 2000, the Company had fewer lines of business over which to spread these common costs.[5] (See IP Init. Br., pp. 15-17, 62; IP Ex. 1.34, pp. 5, 7-8, 55-56)) However, Staff provides no valid justification as to why Illinois Power should in this case use labor expense allocation factors to allocate G&I plant and A&G expense to a business it did not conduct in 2000, based on labor expenses that it did not incur in 2000.

Staff argues that "IP is asking ratepayers to pay a penalty for its own decision to divest generation", a decision that Staff notes was made "without any pressure from the Commission." (Staff Init. Br., p. 13) Staff also contends that the divestiture decisions may have been inconsistent with what Staff refers to as "least cost ratemaking." (Id.) This is nothing more than bureaucratic second-guessing. Staff has pointed to nothing from either Docket 99-0209 (in which the Commission approved the transfer of IP's fossil generation to the company now known as Dynegy Midwest Generation, Inc. ("DMG")) or Dockets 99-0409, 99-0410 & 99-0411 (Cons.) (in which the Commission approved the sale of IP's

[5] Staff asserts at page 17 of its Initial Brief that "Company witness Carter did not use the labor allocator for separating out the generation component of General and Intangible Plant and A&G accounts", citing IP Ex. 1.34, p. 5 What Ms. Carter in fact said at page 5 of IP Ex. 1.34 is that "IP's G&I plant and A&G expenses are common costs that support all lines of business in which IP is engaged (i.e., gas, electric transmission and electric distribution)"; that "the fact that a portion of IP's common costs in 1997 were allocated to the generation function by use of the labor allocator, in order to set electric delivery services rates, does not make these costs 'generation-related'"; and that "[t]he G&I plant and A&G expenses recorded on IP's books in 2000, after IP sold its generation assets and exited the generation business, remain common costs which support all of IP's lines of business. Consistent with the Commission's requirement in the 1999 DST case, IP has used the labor allocator to allocate these common costs among the businesses in which IP was engaged in 2000." Staff did not refute any of this testimony. In addition, contrary to Staff's implication at page 17 of its Initial Brief, IP used labor expense allocation factors to allocate G&I plant and A&G expense to distribution rate base and operating income in this case, and is not advocating that the Commission use an asset separation study to assign or allocate common costs among functions.

nuclear generating station to AmerGen) to show that Staff (or anyone else) argued contemporaneously that either of these sales was a bad idea.[6] Indeed, it is noteworthy that Staff focuses its arguments on IP's sale of its fossil generation to its affiliate, DMG (see Staff Init. Br., pp. 14-17, 22), and never mentions IP's sale of the Clinton nuclear plant to AmerGen. It is unlikely that there is anyone, on Staff or otherwise, who believes that Illinois Power ratepayers would be better off today if IP still owned Clinton.[7]

As to Staff's assertion that IP's allocation of G&I plant and A&G expense in this case "raises the issues of least cost ratemaking", there is no such thing as "least cost ratemaking" [8]. Staff has cited no statute, regulation or Commission order that defines or establishes "least cost ratemaking." (See Staff Init. Br., p. 13) Company witness Carter did testify that IP has an obligation to provide service to delivery services customers at least cost. (Tr. 147; Staff Init. Br., p. 13) However, the issue in this case has nothing to do with the provision of

[6]Staff can also point to nothing in either docket to show that it contended contemporaneously that IP was not transferring enough G&I plant to the new owners of the fossil and nuclear generation stations. As described in IP's Initial Brief, G&I plant that had an original cost totaling $55 million was transferred to DMG and Amergen in these transactions. (IP Init. Br., pp. 18-19) In fact, in this case, Staff did not identify any additional G&I plant items that Staff contends should have been transferred to DMG or to AmerGen. (See IP Ex. 1.34, pp. 16-17) Moreover, in Docket 99-0209, IP's filing included (as required by §16-111(g) of the Public Utilities Act ("PUA")) a certification from its Chief Accounting Officer that "the accounting entries related to the transfer of assets and liabilities from Illinois Power Company to [DMG], are in accordance with the guidelines for cost allocations specified in the Services and Facilities Agreement between Illinois Power and Illinova Corporation as approved by the Illinois Commerce Commission in Docket No. 94-0005." (IP Ex. 1.34, pp. 11-12) Review of the Order in Docket 99-0209 shows that neither Staff nor any other party took issue with the accuracy of that certification.

[7] As IP pointed out at p. 25 of its Initial Brief, in the 1999 DST Case, 66% of IP's generation labor expense was nuclear generation labor, and only 34% was fossil generation labor. Therefore approximately 66% of the G&I plant and A&G expense that was allocated to "generation" in the 1999 DST Case was allocated to nuclear generation, and only 34% was allocated to fossil generation.

[8] IIEC's Brief contains a similarly unsupported reference to "least cost provision of delivery services." (IIEC Init. Br., p. 11)

service at least cost – it is, rather, an issue of how to spread common costs that are already on the utility's books among its various lines of business for ratemaking purposes. Illinois Power has shown in this case that it is providing delivery services on a least-cost basis by disposing of plant it no longer needs and taking other actions to reduce operating costs.[9] (See IP Init. Br., pp. 27-28, 65-70) Staff provided no rebuttal to the Company's evidence on this point, and identified no items of G&I plant or A&G expense that Staff contended were imprudent, excessive or not "least cost."

At pages 69-70 (§II.C.3.e.iv) of Illinois Power's Initial Brief, IP fully responded to Staff's arguments about savings from the Dynegy-Illinova merger. (See Staff Init. Br., pp. 13-14) However, the issue of whether IP should be required to allocate a portion of its G&I plant and A&G expense in this case to a business it no longer owns, based on labor expense it did not incur, has nothing to do with the extent to which cost savings have resulted from the Dynegy-Illinova merger. Staff's reliance on arguments about "least cost ratemaking", merger savings, IP's "assurances" in Docket 99-0209 (see below), and the current Ameren DST case (see below) simply show how little substance there is to support Staff's position on the treatment of G&I plant and A&G expenses in the distribution revenue requirement.

Illinois Power also responded to Staff witness Lazare's discussion of Illinois Power witness Dreyer's testimony from Docket 99-0209 (see Staff Init. Br., pp. 14-17), at pages 23-26 (§II.B.3.c.iii) of IP's Initial Brief. In the course of its discussion of Docket 99-0209 in its Initial Brief, Staff asserts that IP's allocation of G&I plant and A&G expense to distribution in this case lays "the foundation for higher rates for all electric customers when their bundled

[9] In addition to the reductions in headcount in A&G functional areas between 1997 and 2000 that were described at pages 65-70 of IP's Initial Brief, the Company also reduced headcount in the Transmission and Distribution functional areas by 131 employees (7%) from 1997 to 2000. (IP Ex. 1.34, p. 50)

rates are updated to reflect the common costs calculated for the newly constituted IP." (Staff Init. Br., p. 15) Staff provides no citations to the record to support this assertion, which in any event is wrong, because the allocation issue in this case would have no impact on bundled rates. Specifically, if common costs are allocated to distribution as proposed by the Company in this case, then those costs will be reflected in the "distribution" portion of bundled rates when they are next reset (i.e., sometime after December 31, 2004). On the other hand, if Staff's position that a portion of IP's common costs must be allocated to "generation" were to prevail, then when IP's bundled rates are next reset, the common costs allocated to "generation" will be included in the "generation" component of the bundled rates. In short (and contrary to Staff's assertion), the resolution of the cost allocation issue in this case will be a matter of indifference when it comes to re-setting IP's bundled rates.[10]

Illinois Power also addressed Staff's arguments relating to the just-completed Ameren DST case (Staff Init. Br., pp. 17-18) at pp. 26-27 of IP's Initial Brief. Staff fails to mention that Staff witness Lazare admitted that in the test year used in the Ameren DST case, Ameren still owned and operated generation facilities. (Tr. 760-61) Ameren's transfers of generating facilities occurred after the test year. Mr. Lazare presented no evidence or information to indicate that Ameren will continue to allocate G&I plant and A&G expenses to "generation" in future cases that involve test years in which Ameren no longer owns (or owns a reduced amount of) generation facilities.

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[10] Moreover, demonstrating how confused and unsupported its position really is, Staff contradicts its own argument in the very next paragraph on page 15 of its Initial Brief by asserting that IP is "lay[ing] the groundwork for delivery services rates to rise relative to bundled rates." Further, as to Staff's latter assertion, it ignores the fact that increases in DST rates are offset by corresponding decreases in customers' transition charges ("TC"), in accordance with the statutory formula for TCs in §16-102 of the PUA.

Staff disputes Ms. Carter's testimony that the effect of Staff's proposed treatment of G&I plant and A&G expense in this case is to allocate a portion of IP's bucket trucks, backhoes, and other types of vehicles and equipment that are used in the distribution business, to "generation". (Staff Init. Br., pp. 21-22) However, Staff cannot avoid the mathematical fact that the result of its position (that the same percentage of total G&I plant that was allocated to distribution in the 1999 DST Case should be used in this case) is to allocate a portion of the cost of <u>every</u> G&I asset of the Company to "generation", even those G&I assets that are used exclusively or predominantly for distribution purposes. It should be noted that in the 1999 DST Case, by virtue of the use of a labor expense allocator to allocate all G&I plant, a portion of the cost of G&I plant that was used predominantly by the generation business – including a portion of the $55 million of G&I plant that IP sold to DMG and AmerGen in connection with the sale of its generation -- was allocated to distribution. In this case, the G&I plant that had been predominantly associated with the generation function has been sold and therefore no part of it will be allocated any more to distribution. Yet Staff wants a portion of the costs of the G&I plant assets that are used predominantly or exclusively by the distribution business to continue to be allocated to "generation." Staff's approach is one-sided and unfair. More generally, Staff wants the distribution function to benefit forever from the fact IP previously was able to spread common costs over the generation function as well as the gas, electric transmission and electric distribution functions, without any analysis as to whether IP's G&I plant and A&G expenses subsequent to the divestiture of its generation business are reasonably required to support IP's remaining business functions, including electric distribution.

Staff argues that IP should be able to allocate a portion of the costs of its headquarters building (and of other common plant) to the owner of its former generation units, DMG, citing Ms. Carter's testimony at transcript page 180.[11] (Staff Init. Br., p. 22) Here's what Ms. Carter in fact said:

> Q. Are you saying that there's no way that IP could allocate portions of its A&G expenses to other Dynegy subsidiaries?
>
> **A. If we do work for another subsidiary, we can bill them under the Services & Facilities Agreement, but we cannot just allocate our A&G costs to another subsidiary under the Services & Facilities Agreement** such as Dynegy can under Section 5.3. We talked earlier about work we've done for DMG and for Dynegy earlier. We do bill that back to them based on the Services & Facilities Agreement but under Section 5.2 under Fully Distributed Costs.
>
> Q. So you are saying that it possible to allocate portions of IP's G&I plant to business functions and assets that are now owned by separate legal entities such as Illinova Generating?
>
> A. No, that's not what I'm saying.
>
> Q. Is it possible?
>
> A. **Only to the extent that one of those subsidiaries would be using a G&I facility**, then we would appropriately allocate a piece of that to that subsidiary under Section 5.2. (Tr. 179-80; emphasis supplied)

In other words, in accordance with the SFA that this Commission has approved, IP can bill DMG for the use of G&I assets (and for A&G expenses) *in connection with services provides to DMG*. Contrary to the inference Staff attempts to create, the SFA does not provide carte blanche for IP to allocate common costs to DMG outside the context of providing specific

[11] Once again, Staff bases its argument solely on DMG, and ignores AmerGen, which purchased the Clinton nuclear plant from IP, and is not an affiliate of IP nor subject to the Services & Facilities Agreement ("SFA"). As noted earlier in this Reply Brief, for the 1997 test year used in the 1999 DST Case, 66% of IP's generation labor expense was nuclear-related and only 34% was fossil-related, hence approximately 66% of the G&I plant and A&G expense allocated to "generation" in the 1999 DST Case were allocated to nuclear generation, not to fossil generation.

services to DMG. Moreover, in this case, Ms. Carter detailed IP's billings to DMG for services during the test year, and testified that DMG was billed for these services based on IP's fully-distributed costs, as required by the SFA. (See IP Init. Br., p. 23) Staff witness Lazare did not present any evidence that Illinois Power provided any G&I facilities or A&G services to DMG for which IP was not properly compensated under the SFA, or that IP incorrectly accounted for the revenues for such services, or the underlying costs.[12] (Tr. 770-73)

Staff's specific proposed adjustments to G&I plant and A&G expenses are arbitrary and inappropriate. Staff's adjustment is **not** based on application of the labor allocator. Rather, Staff proposes to allow IP to increase G&I plant over the amount allowed in the 1999 DST Case by the same percentage amount as the percentage increase in distribution plant in this case over the amount allowed in the 1999 DST Case. (Staff Init. Br., pp. 19-20) Staff's proposed adjustment is not cost-based, and it is not based on any analysis of which of IP's G&I assets and A&G costs are needed to support the distribution business. Staff's adjustment is premised on an assumption that the Commission found, in the 1999 DST Case, that there is a fixed ratio between G&I plant and distribution plant, and between A&G

[12] Although not proposing an adjustment to A&G expense similar to that proposed by Staff, CUB/AG assert that since IP's fossil generating units were divested to an affiliate, they "should still absorb the same relative portion of administrative and general expenses as if the facilities were still owned by IP." (CUB/AG Init. Br., p. 18) There is no basis for this assertion. As noted elsewhere in this brief and in IP's Initial Brief, DMG, the owner of the fossil units, now obtains most of its administrative and overhead services from Dynegy; IP properly billed DMG for those A&G services that IP did provide to DMG during the test year, at fully distributed costs in accordance with the Commission-approved SFA; and both the revenues from the provision of services to DMG as well as the related costs have been recorded below the line, so that they have no impact on the determination of the distribution revenue requirement in this case. (See IP Init. Br., pp. 22-23, 64) Further, even if CUB/AG's assertion were correct, it does not account for the fact the IP's nuclear generating station, which in the 1999 DST Case was allocated 66% of the "generation-related" A&G, was sold to an *unaffiliated* entity. (IP Ex. 1.63, p. 12)

expense and distribution O&M, that must always be maintained. But the Commission made no such finding in the 1999 DST Case.

In addition, Staff would apply its adjustment even to IP's G&I plant assets that have been placed in service subsequent to IP's sale of its generating stations in 1999, not just to the G&I plant that was in service prior to IP's divestiture of its generation assets. (Staff Init. Br., p. 18) Staff asserts that IP has failed to establish that its post-1999 G&I plant additions "could not serve other functions as well." (Id.) This is a rather meaningless observation, since it is in the nature of common plant and expenses that they can serve numerous functions, including non-utility functions (e.g., a desk or a personal computer). However, the implication of Staff's position is that IP is continuing to invest money in G&I plant to use in a generation business the Company no longer owns. There is absolutely no basis for the Commission to reach this conclusion. Further, contrary to Staff's bald assertion, review of the Company's descriptions of these G&I plant additions makes it clear that they have not been undertaken, and placed in service to serve, the generation business.[13]

Staff's proposed adjustments to G&I plant and A&G expense would not result in a legally-sustainable order in this case. Staff's proposals must be rejected.[14]

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[13] See, e.g., IP Ex. 2.4, p. 2 (Galesburg Service Facility and Distribution Reliability Assessment Tool; latter is for "system reliability analysis to be conducted using the Company's electric distribution circuit performance and outage data"); IP Ex. 2.5, p. 2 (Electric Compliance System, will be "utilized to manage the procedural and maintenance activities of the Company's electric distribution system"); IP Ex. 2.9, pp. 3-4 (vehicle purchases for electric distribution and replacement of mobile data terminals in IP's line trucks); and IP Ex. 2.10, p. 3 (Reliability Centered Maintenance program – will be used to monitor substation facilities to identify maintenance needs).

[14] Staff's A&G adjustment, as described in page 20 of its Initial Brief, is overstated because it uses $47,141,000 as IP's requested A&G expense component of the distribution revenue requirement. As noted earlier in this Reply Brief, IP is only requesting $41,682,000 of A&G expense in the distribution revenue requirement.

ii. <u>IIEC's Arguments Do Not Support its Position</u>

Although IIEC makes one passing reference to the fact that Illinois Power has divested its generation (IIEC Init. Br., p. 8), IIEC's principal objection to Illinois Power's proposed amounts of G&I plant and A&G expense in the distribution revenue requirement seems to be simply that they are too large. IIEC, like Staff, proposes arbitrary limitations on the amounts of G&I plant included in rate base and A&G expense included in operating expense. IIEC's adjustments, like Staff's, should be rejected.

IIEC seeks to limit the amount of G&I plant and A&G expense in the revenue requirement such that the same ratio between these items and distribution O&M that occurred in the 1999 DST Case is maintained. (IIEC Init. Br., pp. 6-9) IIEC's proposal is not based on any actual analysis of IP's G&I plant or A&G expense to identify G&I assets or A&G expenses that are excessive, imprudent, or not needed to support the distribution business. IIEC's proposal is premised on the assertion that in the 1999 DST Case, the Commission "found" that for each $1.00 of distribution O&M, 23.7 cents of A&G was needed to provide delivery services. (IIEC Init. Br., p. 7) But the Commission made no such finding. The 23.7 cents figure is simply a mathematical calculation performed by IIEC using numbers from the 1999 DST Case. Certainly, there is nothing in the 1999 DST Case or the 1999 DST Order whereby the parties litigated, and the Commission determined, what an appropriate ratio should be between A&G expense and distribution O&M expense.

Similarly, IIEC asserts that in the 1999 DST Case "[t]he Commission found . . . that more than half of IP's requested G&I Plant costs were not related to distribution", and the same ratio should be applied in this case. (IIEC Init. Br., p. 8) While Appendix A, Schedule 3, column (1) to the 1999 DST Order shows that the Commission there made a $95,233,000 "functionalization adjustment", IIEC has ignored the fact that subsequently, IP transferred some $55 million of G&I plant to the new owners of its generating stations. (See IP Init. Br., pp. 18-19) Since IIEC now proposes to disallow another $69.9 million of G&I plant (IIEC Init. Br., p. 9), it would appear that IIEC, like Staff, is attempting to disallow costs for G&I plant additions that have been placed in service since IP sold its generating stations. In IIEC's case, this attempt contradicts the testimony of its own witness, Mr. Phillips, who testified that "The additions and adjustments to net Intangible and General Plant requested by IP should be allowed to the extent IP presents valid reasons for their inclusion." (IIEC Ex. 3, p. 9) Although IP presented detailed exhibits describing its proposed G&I capital additions, neither Mr. Phillips nor any other IIEC witness opposed inclusion of any specific project or component of those additions in rate base. Thus, IIEC's blunderbuss adjustment does not even take into account its own witness' testimony.

IIEC claims that IP did not justify its levels of G&I plant and A&G expense. (IIEC Init. Br., pp. 9-11) IIEC's assertion is without merit. IP presented a detailed explanation of the changes in its G&I plant from 1997, the test year in the 1999 DST Case, to 2000, the test year in this case, including describing the G&I plant it sold to the buyers of its generating stations and other actions it has taken to eliminate G&I plant not needed to support its remaining lines of business. In addition, the Company explained and justified its individual additions to G&I plant costing in excess of $250,000 that were placed in service between 1997 and 2000, and the G&I plant additions being placed into service subsequent to December 31, 2000, that IP is proposing to include in rate base in this case. Moreover, in the 1999 DST case, IP described and justified its G&I plant additions placed into service subsequent to 1992 (the last time an electric rate base was determined for IP). (See IP Init.

Br., pp. 18-20, 27-28) Company witness Ms. Carter specifically testified that IP's remaining G&I assets continue to be needed to support the Company's remaining lines of business. (IP Ex. 1.34, pp. 5, 14; IP Ex. 1.63, pp. 9-10) IIEC did not refute any of this evidence. Similarly, Illinois Power presented detailed analysis of the changes in its electric A&G expenses and employee levels since 1997. (See IP Init. Br., pp. 65-70) Again, IIEC did not refute any of this evidence.

IIEC instead complains that IP did not conduct any studies to show that it has the most efficient and economical levels of G&I plant and A&G expense for providing delivery services. IIEC apparently contends such studies are required because the Commission is "essentially setting a delivery services revenue requirement from scratch." (IIEC Init. Br., pp. 9-10) Illinois Power did not conduct such studies, but they were not necessary, or even appropriate. As summarized in the preceding paragraph, IP justified its levels of G&I plant and electric A&G expenses, without any contradictory evidence from IIEC. As to "starting from scratch", IIEC should hope that it doesn't get what it wishes for. IIEC and other delivery services customers benefit from the use, in setting rates, of the depreciated original cost of distribution, general and intangible plant assets that IP has placed in service over many years. No doubt, there are some items of distribution, general and intangible plant placed in service many years ago that would not be installed today in light of more modern technologies and methods. Overall, however, the Commission can be assured that if IP were "starting from scratch" today to build a new, stand-alone distribution utility, the resultant revenue requirement would be much higher than anything proposed in this case.

IIEC attempts to take issue with IP Exhibit 1.72, which shows that IP's ongoing level of electric A&G expense has <u>decreased by $37.2 million (53.2%) from 1997 to 2000</u>, to

$34.2 million. IIEC asserts that IP has not in fact removed the non-recurring 2000 expenses listed in IP Exhibit 1.72 for ratemaking purposes, and that IP is requesting $41.8 million of A&G expense in the distribution revenue requirement, not $34.2 million. (IIEC Init. Br., pp. 10-11) IIEC's criticisms miss the mark. First, three of the six non-recurring items listed on IP Exhibit 1.72 have been completely removed from the distribution revenue requirement in this case (salaries and benefits associated with transition employees, correction of SFA allocation methodology and Duke Engineering litigation expense (see pp. 52-53, 39-40 and 39, respectively, of IP's Initial Brief)).[15] Two of the remaining three items (severance costs accrued in 2000 and the $5.5 million accrual for injuries and damages) have been removed from the test year expenses but are being amortized over multi-year periods, so the annual amortization is reflected in the distribution revenue requirement. (See pp. 52-53 and 71-73, respectively, of IP's Initial Brief) Only the item for incentive compensation accrued expense remains in the distribution revenue requirement.[16] Second, IP Exhibit 1.72 does not reflect post-test year adjustments to operating expense, such as adjustments for the load research project, rate case expense, postal rate increase, increased insurance costs, wage and salary increases in 2001, and increased FICA expense in 2001, as well as other one-time ratemaking adjustments such as for the operations compliance program startup costs and storm damage

[15] All of the values shown on IP Ex. 1.72 are the total electric utility values, not the allocated distribution values.

[16] IIEC also notes that the A&G expense amount for 2000 on IP Ex. 1.72 includes the expense for IP's allocated share of bonuses paid to Dynegy executives. (IIEC Init. Br., p. 11) However, IP has also removed these amounts completely from the proposed distribution revenue requirement. (See IP Init. Br., p. 38)

expense normalization, none of which have been contested by IIEC (or any other party).[17] Overall, however, IP Exhibit 1.72 shows that Illinois Power achieved a <u>substantial</u> reduction in electric A&G expenses from 1997 to 2000, and manifests ongoing efforts by the Company to conduct its electric operations in an efficient and economical manner.

The "ratio" methods proposed by IIEC and Staff for determining the amount of G&I plant and A&G expense to be included on the distribution revenue requirement, in addition to being completely arbitrary and premised on a Commission "finding" that was not in fact made in the 1999 DST Case, would constitute bad policy. For example, Staff and IIEC's methods would penalize a utility for making investments in G&I plant (such as computer equipment and software, telecommunications equipment, and other information technology assets) in order to reduce direct distribution expenses (such as O&M or customer accounts labor expense). Staff's and IIEC's "ratio" method would thus discourage such cost-effective investments. Similarly, Staff's and IIEC's "ratio" approach would discourage utilities from taking other actions to reduce direct distribution O&M expense, since such efforts would carry a penalty of the disallowance of a commensurate amount of G&I plant and A&G expense from the revenue requirement. Thus, Staff's and IIEC's approaches would discourage, rather than encourage, the provision of delivery services on an economical, efficient and least-cost basis. Their adjustments should be rejected.

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[17] Because it does not take these and other pro forma adjustments into account, IIEC's math exercise at page 11 of its Initial Brief to attempt to justify its proposed A&G expense amount is incomplete and meaningless.

d. Capitalization of Severance Costs

Staff contends that IP should not have capitalized a portion of its severance and early retirement program costs.[18] (Staff Init. Br., pp. 32-35) Most of Staff's arguments on this issue were addressed in §II.B.3.d of IP's Initial Brief.

Staff's argument that the severance and early retirement costs should not be capitalized because they are not "labor costs . . . incurred by utility employees engaged on construction work", in accordance with Electric Plant Instruction 3(A)(2) of the Uniform System of Accounts ("USOA"), is a false issue. (Staff Init. Br., p. 33) Electric Plant Instruction 3(A)(2) refers only to direct construction labor. (Tr. 309-10; see IP Init. Br., p. 30) If only those costs described in Electric Plant Instruction 3(A)(2) could be capitalized to construction, no A&G costs would ever be capitalized to construction, but obviously, this is not the case. In fact, Electric Plant Instructions 3(A)(12) and 4 provide for the capitalization to construction of A&G costs, including those recorded in Accounts 920 and 926, the accounts in which IP recorded its severance payments and early retirement program costs. (Tr. 309-11; Rev. Staff Ex. 10.0, p. 12; see IP Init. Br., pp. 30-31) Staff has not contended that it was incorrect for IP to record the severance costs and early retirement costs in Accounts 920 and 926.

Staff argues that capitalization of a portion of the severance and early retirement costs is not supported by Electric Plant Instruction 4 because Instruction 4 prohibits capitalization of overhead costs to construction based on "arbitrary percentages." (Staff Init. Br., pp. 34-35) Staff's argument is inconsistent with Staff witness' Hathhorn's testimony. As IP witness

[18] Staff's arguments on the capitalization issue are set forth in §III.B.3 of its Initial Brief, wherein Staff argues against recovery of any of the severance and early retirement program costs.

Carter testified, IP annually determines the percentage of costs recorded in Account 920 to be capitalized based on a study of the level of support provided to other business functions; based on that study, the percentage of A&G to be capitalized is determined. IP used this percentage to determine the amount of severance costs to be capitalized, consistent with its treatment of all other A&G costs in this regard. Similarly, IP capitalized the same percentage of early retirement costs that it used in capitalizing all other costs charged to Account 926. (IP Ex. 1.63, pp. 23-24) Staff witness Hathhorn agreed that IP allocates a portion of A&G to construction on the basis of "special studies . . . made periodically" in accordance with Electric Plant Instruction 4; that IP used the same percentage to allocate severance and early retirement costs to construction as it used to allocate all other costs recorded in Accounts 920 and 926 to construction; and that she did not take issue with the percentage IP used in 2000 to allocate A&G costs to construction. (Tr. 311-12) In short, as Ms. Hathhorn's testimony acknowledges, IP did not violate the prohibition on "arbitrary percentages" in allocating a portion of severance and early retirement costs to construction.

In summary, IP's capitalization of a portion of the severance and early retirement costs to construction was in conformance with the USOA. It is Staff that is engaging in selective application of the USOA. Staff has provided no justification under the USOA (or otherwise) for treating these particular costs differently from all other costs charged to Accounts 920 and 926. Staff's position must be rejected.

e. <u>Deferred Tax Debit Balances</u>

CUB/AG contend that four deferred tax debit balances identified by Mr. Effron should be removed from the deferred tax reserve that is deducted in determining rate base, on the grounds that the related reserves, deferred credits or accruals have not been included in rate base. (CUB/AG Init. Br., pp. 12-15) As shown in §II.B.3.e of IP's Initial Brief, CUB/AG's proposed adjustment is selective and inconsistent with the theory on which accumulated deferred taxes are deducted from rate base, namely, that accumulated deferred taxes represent ratepayer-supplied capital, not investor-supplied capital, and that the utility should not earn a return on the portion of its assets that are supported by ratepayer-supplied capital. CUB/AG have identified no precedent for determining the amount of the deferred tax deduction from rate base by an item-by-item matching of deferred tax balances against the related reserves, accruals and other contra items.

CUB/AG point out that IP witness Carter identified numerous deferred tax credit balances that relate to items which are not considered in determining rate base, and which therefore should also be removed from the balance of accumulated deferred taxes if Mr. Effron's proposal were accepted. (CUB/AG Init. Br., p. 14; see IP Ex. 1.63, pp. 21-22, and IP Ex. 1.69) CUB/AG argues that one of those deferred tax credit balances, that relating to Loss on Reacquired Debt, should not have been included on Ms. Carter's list because the unamortized loss on reacquired debt is deducted, and the amortization is included, in calculating the embedded cost of long-term debt, which, according to Mr. Effron, is the equivalent of including the unamortized loss on reacquired debt in rate base. (CUB/AG Init. Br., p. 14) This argument represents an eleventh-hour departure from the rationale that Mr. Effron had offered for his adjustment, namely, that the deferred tax debit balances he proposed to remove were related to reserves, deferred credits or accrued liabilities "that are not recognized in the calculation of rate base." (GCI Ex. 2.0, p. 28; see also Id. at p. 28, lines 12-13 and 18-19 and p. 29, lines 1-3) Further, his contention as to this one item is incorrect. Through the inclusion of the amortization of the Loss on Reacquired Debt in the calculation of the embedded cost of long-term debt, the utility realizes recovery of the loss on reacquired debt, but does not earn a return on the loss. It would only be by including the unamortized balance of the Loss on Reacquired Debt in rate base that the utility would realize both recovery of and return on this amount.

In summary, Mr. Effron's adjustment to remove certain deferred tax debit balances from the deferred tax reserve should be rejected as inconsistent with the theory on which accumulated deferred taxes are deducted from rate base, and unsupported by Commission precedent. If, however, the Commission were to depart from prior practice and engage in an item-by-item matching of deferred tax balances deducted from rate base to the related reserves, deferred debits and credits and other accruals included in rate base, then a complete adjustment, as presented by IP witness Carter in IP Exhibit 1.69, should be used. This adjustment would increase the deferred tax reserve, and thereby decrease distribution rate base, by a net amount of $625,913. (IP Ex. 1.69)

f. Incentive Compensation Capital Adjustment

This adjustment to rate base, if any, is dependent on the extent to which the Commission disallows any of IP's test year incentive compensation costs, a portion of which were capitalized and the remainder of which were expensed. Staff's proposal to disallow incentive compensation payments is discussed in §II.C.3.a of IP's Initial Brief and §II.C.3.a of this Reply Brief. However, IP does agree with Staff that if the Commission adopts any of IP's four alternate adjustments for incentive compensation payments, the adjustment should affect both operating expenses and rate base. (See Staff Init. Br., pp. 45-46)

C. Distribution Operating Expenses

1. Overview of IP's Proposed Operating Expense Statement

Illinois Power continues to propose the same distribution operating expense statement that is summarized in §II.C.1 of its Initial Brief and detailed in Rev. IP Exhibit 3.24.

2. Uncontested Adjustments to Distribution Operating Expenses

No party has raised any issues concerning any of the uncontested adjustments to distribution operating expenses listed in §II.C.2 of Illinois Power's Initial Brief. Staff discusses certain of the uncontested adjustments in §III.A of its Initial Brief. Illinois Power agrees with Staff's statement of those uncontested adjustments. With respect to the first uncontested adjustment discussed by Staff, "Increased Personnel Costs" (Staff Init. Br., p. 22), IP notes that this item was originally proposed by the Company as a pro forma adjustment to actual 2000 results, but that the Company withdrew this adjustment in surrebuttal (as Staff notes). Therefore, this adjustment is not reflected in IP's proposed distribution operating expense statement or on Rev. IP Exhibit 3.24, and does not need to be.

3. Contested Adjustments to Distribution Operating Expenses

a. Incentive Compensation Expense

Staff opposes including any incentive compensation expense in the distribution revenue requirement. (Staff Init. Br., pp. 35-46) CUB/AG propose disallowance of $4,563,000 of the jurisdictional test year incentive compensation expense of $5,159,000.[19]

[19] CUB/AG propose disallowance of $4,563,000 of incentive compensation expense, which was the amount paid to non-union employees, because this portion of the incentive compensation program was tied to corporate earnings. CUB/AG would allow recovery of $596,000 of incentive compensation expense, which was the amount paid to union employees of the Company. (CUB/AG Init. Br., pp. 16-17) Thus, CUB/AG's basis for disallowing the expense for the non-union portion of the program is essentially the same as

(CUB/AG Init. Br., pp. 16-17) Illinois Power thoroughly addressed these parties' arguments in §II.C.3.a of its Initial Brief, and there demonstrated that the Commission must make provision for this reasonable and necessary business expense in determining the revenue requirement. The fundamental issue for the Commission in connection with this topic is this: the Commission may allow IP's actual test year jurisdictional incentive compensation expense, or one of the four alternative adjustment amounts suggested by the Company, or a fifth alternative amount suggested by Staff's brief (see below), but continuing to disallow all recovery of this reasonable and necessary expense cannot be justified. Rote recitation of the justifications for disallowing incentive compensation cited in prior orders, which seem to have taken on a life of their own – and which is essentially Staff's "analysis" of this issue – can no longer justify the disallowance of such a significant portion of Illinois Power's total compensation expense.

Staff contends that incentive compensation expense should be disallowed because the funding of the incentive compensation pool is based on the earnings of Illinois Power and its corporate parent, Dynegy (and, as a result, other Dynegy subsidiaries), asserting that corporate earnings performance does not benefit IP customers, non-utility operations should fund the achievement of their own goals, and allowing recovery of incentive compensation expense "creates a circularity problem." (Staff Init. Br., pp. 36-38) Illinois Power believes that its customers do benefit if IP experiences strong earnings (which, of course, necessarily contributes to stronger earnings by its corporate parent). However, the more important point is that IP's customers benefit from the incentive compensation program because it enables IP to attract and retain qualified employees; it enables IP to provide a part of its overall

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Staff's first objection, i.e., that the plan is based on financial goals that do not directly benefit customers.

employee compensation without locking in annual pay increases into its costs and without incurring associated pension and benefits costs; and it requires employees to meet individual performance objectives tied to such factors as budget and cost control, safety and reliability objectives, and project completion objectives, in order to receive incentive compensation payments. (See IP Init. Br., pp. 44-47)

Staff does not really dispute the existence of these benefits; indeed, although the employees' success in meeting their <u>individual</u> performance objectives determines whether and to what extent an employee receives any incentive compensation payment in a year, Staff did not even bother to review the individual performance objectives. (Staff Init. Br., p. 37) Staff cites its witness' testimony (the witness who eschewed reviewing information on the individual objectives even though this is the most important part of the program in terms of motivating individual employee performance) to the effect that it is unlikely that IP employees will be strongly motivated to better performance by an incentive compensation program that is funded based on Dynegy's financial performance. (<u>Id</u>., pp. 37, 38) However, the Staff witness' background includes absolutely <u>no experience</u> with incentive compensation plans (not even as a participant), nor with any other aspect of human resources, including hiring employees or determining their compensation. (Tr. 280-82) IP witness Ellen Hearn, an experienced human resources professional who has worked in this field for both regulated and unregulated companies, and who works with these issues on a daily basis (Rev. IP Ex. 10.1, pp. 1-2), testified unequivocally that IP employees are motivated by the incentive compensation program whose funding is based (at least in part) on Dynegy corporate earnings, and that in fact the motivational aspects of the program were strengthened in this regard after the merger, when program funding could be based on Dynegy's earnings rather than just IP's earnings. (Rev. IP Ex. 10.1, pp. 8-9; IP Ex. 10.2, pp. 2-3)

Staff's "circularity" argument, although a recitation of a justification for disallowing incentive compensation expense that has appeared in prior Commission orders (see Staff Init. Br., p. 37), is not persuasive in this instance. Staff's argument is that by including incentive compensation expense in the revenue requirement, the Commission allows the utility to reach the earnings target that triggers incentive compensation payments. Under IP's program, any "circularity" is minimal at most. Funding of IP's incentive compensation program does not depend on IP (or its corporate parent) reaching a threshold level of earnings; rather, it is funded as a percentage of earnings (in 2001, up to XXX of Dynegy's earnings before income taxes (Tr. 334; Staff Cross Ex. 3)). Thus, at any level of earnings, there will be commensurate funding of the incentive compensation program. In this case IP is asking to recover $5,159,000 of jurisdiction test year incentive compensation expense. Based on the current incentive compensation program, if this amount ($5.2 million) of incentive compensation expense were allowed in the revenue requirement, and, all other things equal, the resulting incremental revenues flowed through dollar-for-dollar to IP's earnings before taxes and thence to Dynegy's earnings before taxes, the incentive compensation pool would be increased by only XXX of $5.2 million. (See Tr. 334-36) Moreover, as discussed above, the extent of payments to individual IP employees would depend on the extent to which each employee met his/her individual performance objectives.

Staff also argues that IP did not provide any studies to show the extent to which costs were controlled or reduced as a result of employees meeting their individual performance objectives. (Staff Init. Br., pp. 38-39) However, as Staff acknowledges, the Company is able to measure the success of the program each year by the extent to which individual employee objectives (which stress safety, customer service, reliability and cost control) were achieved. (Id., p. 39; IP Ex. 10.2, p. 2) As Ms. Hearn explained:

> Individual goals are a key to the program. Because individual goals frequently have cost control or budgeting objectives, they are related to the ultimate corporate earnings or other financial goals. Achieving the corporate goal is a function of achievement of the individual goals. If individual cost control and budget-related goals are not met on a widespread basis, then corporate earnings will be affected and a high [incentive compensation] payout will be unlikely. (IP Ex. 10.2, p. 2)
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> . . . the individual employee goals are frequently based on cost control or budgeting objectives, usually at the departmental level or below. Whether individual objectives are achieved is carefully reviewed between the employee and his or her department or section head. By monitoring the extent to which individual goals are achieved, the Company is able to monitor the extent to which the [incentive compensation program] is successful in controlling costs. Each department is responsible for monitoring and staying within its budget. Achieving our financial targets by remaining with the budget is the most effective method to determine if the individual goals tied to cost savings were achieved. Failure to remain within budgeted levels would be a direct measurement of failure to meet these goals. (Id., p. 3)

Staff's "ratepayer protection" argument, another justification for disallowing incentive compensation costs that Staff recites from prior Commission orders (Staff Init. Br., pp. 39-40), also does not hold water here. First, the likelihood that IP will make no incentive compensation payments to its employees in a year is extremely low given (1) the Company's track record of having made incentive compensation payments to employees in every year since 1992, and (2) the material portion of the total compensation of IP's employees that incentive compensation has become. (See IP Init. Br., pp. 42, 48) Second, this same reasoning could apply to any cost item included in the utility's revenue requirement, as Staff witness Hathhorn acknowledged (Tr. 330-31); there is no reason to single out incentive compensation for disallowance on this basis. (See IP Init. Br., pp. 48-49) Third, if the

Commission nevertheless believes that the "ratepayer protection" logic continues to be applicable, IP has offered four alternative (and smaller) adjustments for incentive compensation expense that would lessen the likelihood that in a given year, IP will pay out less to its employees in incentive compensation than the amount that was included in setting rates. (See IP Init. Br., pp. 49, 51-52)

The contention that incentive compensation expense varies so much from year to year that it is impossible to identify a "normal" amount of expense (Staff Init. Br., pp. 40-42) also provides no basis to disallow all incentive compensation expense. Many other expenses vary significantly from year to year; they are not therefore disallowed in total, but rather normalized using standard ratemaking techniques. (See IP Init. Br., pp. 49-50) One thing is certain: "zero" is not a "normal" amount of incentive compensation expense for Illinois Power. Staff states that the average jurisdictional incentive compensation expense for the three years 1998 through 2000, $4,807,664, "does not appear to produce a valid result, especially as compared to the Company's 2001 budgeted [incentive compensation] level of $9,509,687."[20] (Staff Init. Br., pp. 41-42) However, given that the expense amounts for the three years were $2.3 million, $5.8 million and $6.3 million, the average of $4.8 million is <u>certainly a more valid result than zero</u>.[21] Illinois Power would accept $4.8 million as the

[20] The $9,509,687 figure is a total Company budgeted amount. The budgeted jurisdictional electric distribution incentive compensation expense for 2001 is $4,095,000 (IP Ex. 1.49). Moreover, it is rather odd that Staff uses the 2001 budgeted expense as the appropriate standard for determining a "valid result", given that four pages later in its Initial Brief (p. 45), Staff argues that using the 2001 budgeted value would be inappropriate for ratemaking purposes in this case.

[21] Staff argues that the fact that IP's incentive compensation expense rose over the three years 1998-2000 "highlights an inherent problem" because the amount of expense is increasing while the number of IP employees is decreasing. (Staff Init. Br., p. 42) What this data in fact illustrates is that IP (like many other regulated and unregulated employers with which IP

jurisdictional electric distribution incentive compensation expense for ratemaking purposes in this case. IP would also accept the 2001 budgeted value of $4.1 million. (IP Ex. 1.49)

Staff contends that studies presented by the Company that "show that incentive compensation is common today" provide no evidence why incentive compensation costs should be recovered from "monopoly ratepayers." (Staff Init. Br., p. 43) Staff is incorrect. Illinois Power must compete to attract and retain qualified employees with the many other regulated and unregulated employers that offer incentive compensation programs as part of their overall employee compensation packages. (Rev. IP Ex. 10.1, p. 7) The widespread use of incentive compensation programs further establishes that this is a reasonable and necessary business expense that IP must be allowed to recover through its rates.

Staff's objections to the Company's four alternative adjustments (Staff Init. Br., pp. 43-45) are simply a series of excuses not to allow any recovery of this reasonable and necessary business expense. Most perplexing are Staff's objections to IP's third (the budgeted level of incentive compensation expense for 2001) and fourth (the additional base pay expense that IP would have to incur if it were to eliminate its incentive compensation program) alternatives: Staff basically asserts that the use of "actual year 2000 expense data" is preferable to these approaches. (Id., p. 45) Yet Staff refuses to consider allowing the actual 2000 expense amount, a portion of the actual 2000 expense amount, or a three- or five-year average of actual expense amounts![22] (See IP Ex. 1.63, pp. 31-33)

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competes to attract and retain employees) is shifting an increasing portion of its employees' compensation to incentive payment programs and away from base pay.

[22] Staff asserts that the fourth alternative is "too contrived and estimated." (Staff Init. Br., p. 45) However, Staff has not disputed the basic premise of this alternative, that if IP did not have an incentive compensation program, it would have to increase its base wages and salaries, and incur additional related pension and benefits expense. (See Rev. IP Ex. 10.1,

In this case, Staff conducted no studies or investigation to determine how Illinois Power's overall compensation expense compares to that of other businesses in general. Nor did Staff conduct any analysis to determine if IP's total compensation paid to its employees in the test year was excessive compared to that paid by other utilities. Staff did not contend that the overall level of compensation the Company paid to its employees in the test year was imprudent. (Tr. 337) Indeed, one suspects very strongly that if in fact IP had no incentive compensation program but its base wage and salary costs were 15% higher, Staff would accept that overall level of compensation for ratemaking purposes without objection. Staff's (and CUB/AG's) objections to including IP's test year incentive compensation expense in distribution operating expenses should be rejected. At a minimum, the Commission should utilize one of the four alternate adjustments presented by the Company (or the additional alternative suggested by Staff's Initial Brief, as discussed above, i.e., the three-year average for 1998-2000). Allowing "zero" for this reasonable and necessary business expense is an unsupportable and unsustainable result.

b. Transition Employee Costs and Severance and Early Retirement Costs

Illinois Power has proposed to remove from test year operating expense the severance and early retirement program costs it incurred in the test year to effect a 297-person reduction in its work force, and to instead recover these costs over a five-year amortization period. IP has also removed from test year operating expenses the expenses for wages and salaries, pension and benefits and payroll taxes paid to or in respect of the terminated employees prior to their departure from the Company; and of course the revenue requirement is also lower by

pp. 12-13) Again, of the alternatives presented, "zero" is the least justifiable amount to allow for this reasonable and necessary expense item.

the amount of the compensation that would have been paid to these employees had they remained with IP. (See IP Init. Br., pp. 52-53) Staff, however, proposes to disallow the jurisdictional portion of the severance and early retirement costs, on the grounds that they are merger transaction costs that the Commission has disallowed (Staff contends) in several recent orders.[23] (Staff Init. Br., pp. 29-35) IP addressed Staff's proposed adjustment in §II.C.3.b of its Initial Brief.[24] Staff's position is based solely on a rote application of certain recent orders and not on any independent analysis of the costs incurred or the resulting savings, and should be rejected.

Staff has cited four recent orders in support of its position. As noted at page 54 of IP's Initial Brief, while all four of the orders indicated that merger "transaction" costs could not be recovered by the utilities involved, only two of the four cases actually involved employee termination costs. More generally, there is no support for Staff's contention that the severance and early retirement costs at issue in this case "were incurred in order to effectuate a change in Company ownership" and "incurred to produce an ownership change" (Staff Init. Br., pp. 29, 32, respectively) Indeed, Staff witness Hathhorn was unable to substantiate this contention in cross-examination, and Company witness Carter testified

[23] Unlike Staff, CUB/AG witness Effron accepted recovery of the severance and early retirement costs, on the grounds that the costs were incurred to produce savings, and included the amortization of the severance and early retirement costs in his proposed revenue requirement. He did argue that the amortization period should be deemed to have started in 2000. (GCI Ex. 2.0, pp. 14-15) His contention regarding the amortization period is addressed later in this section. However, contrary to its own witness' testimony, CUB/AG state in their Initial Brief that they agree with Staff's position that the severance costs should be disallowed in their entirety. (CUB/AG Init. Br., p. 15) CUB/AG's eleventh-hour change of position should be rejected as inconsistent with their own witness' testimony and with the proposed revenue requirement they presented in evidence in this case.

[24] Staff's arguments concerning capitalization of a portion of the severance and early retirement costs (Staff Init. Br., pp. 32-35) are addressed in §II.B.3.f of IP's Initial Brief and §II.B.3.f of this Reply Brief.

unequivocally that the severance costs were not "incurred to produce an ownership change". (Tr. 306-07; IP Ex. 1.63, p. 28; see IP Init. Br., p. 54)

However, the outcome of this issue ought not to depend on whether one can shoehorn the cost in question here into the language used in the prior Commission orders cited by Staff – which is the entire basis of Staff's position – but on an analysis of the costs incurred and the revenue requirement reduction they produced.[25] Here, IP incurred <u>one-time</u> severance and early retirement expenses of $15,083,000 (jurisdictional electric distribution portion) in the test year, to produce <u>annual</u> jurisdictional savings of $14,765,000. The Company is proposing to recover the one-time costs through the distribution revenue requirement over a five-year period at a rate of $3,017,000 per year. Thus, the annual savings to the distribution revenue requirement exceed the related costs by a factor of almost five times. (IP Ex. 1.63, pp. 27-28) Given these facts, the logic that should control is that of the cases cited at page 55 of IP's Initial Brief – cases that Staff dismisses solely because they did not involve mergers (Staff Init. Br., pp. 31-32) – wherein the Commission allowed recovery of early retirement and "re-engineering" program costs that IP incurred to produce savings and increase the efficiency of its operations. Moreover, as the Commission stated in one of the cases cited by Staff, <u>GTE Corporation and Bell Atlantic Corporation</u>, Docket 98-0866 (Oct. 29, 1999), "To the extent that costs are incurred to produce savings and are shown to be both reasonable and directly related, netting is appropriate. <u>As a matter of logic, the only savings that can be realized are net savings.</u>" (<u>Id</u>., p. 41; emphasis added)

[25] One of the two cases cited by Staff that actually involved employee severance costs was the SBC-Ameritech merger case, Docket 98-0555. Illinois Power believes that the Commission's rulings in that merger case were highly fact- and circumstance-specific. IP submits that there is no reason for Illinois Power, or any other utility, to be tarred with the same brush that was used on SBC/Ameritech.

Staff contends that IP's request to recover the jurisdictional electric distribution portion of the severance and early retirement costs is inconsistent with its decision not to request recovery of the gas utility-related portion of these costs. (Staff Init. Br., p. 31) This contention was fully addressed at pages 56-57 of IP's Initial Brief. In summary, electric delivery services customers are receiving the benefits of the savings produced by the severance and early retirement program, through a lower revenue requirement set in this case, whereas IP's gas customers continue to pay the same rates last established in 1993. Therefore, it is perfectly consistent for electric delivery services customers, but not gas utility customers, to pay for the costs that produced these savings.

Staff also apparently contends that a portion of the severance costs should be disallowed because they relate to "non-delivery services activities." (Staff Init. Br., p. 31) However, the Company has only requested recovery of the portion of the severance and early retirement program costs that are properly allocable to electric distribution. (Correspondingly, the savings amount from elimination of the 297 employees that is reflected in the revenue requirement in this case is the jurisdictional electric distribution portion.)[26] (IP Ex. 1.63, p. 30) Staff has not taken issue with the Company's allocation of these costs and savings to electric distribution, which was done consistently with the other expense allocations in this case.

Finally, Staff states that "The Company believes since it actually incurred severance expenses in the test year, rate-recovery should automatically be allowed", citing Ms. Carter's

[26] The 297 employees eliminated in 2000 included 21 employees who were eliminated in connection with IP's exit from the generation business and from retail energy marketing; 15 of these employees were engaged in A&G functions and the other six were engaged in customer service functions. Consistent with the use of the labor allocator to allocate A&G costs, a portion of the severance and early retirement costs, as well as of the related savings, related to these employees is allocated to electric distribution. (IP Ex. 1.63, p. 30)

rebuttal testimony, IP Exhibit 1.34, at page 36. Staff also argues, apparently, that recovery of the costs should not be allowed because they were a one-time cost. (Staff Init. Br., p. 32) Staff's first point is an inaccurate characterization of Ms. Carter's testimony, and its second point ignores common ratemaking practice. All Ms. Carter did at the point in her rebuttal testimony cited by Staff was to note that IP actually incurred these expenses in the test year. Her complete statement was:

> Q. Do you agree with Ms. Hathhorn's treatment of the severance costs?
>
> A. No. The Company actually incurred these expenses in the test year. Further, the expenses were specifically incurred in order to achieve, and in fact resulted, in a reduction in IP's wage and salary expense and related benefits expense which is reflected in the expenses used to set rates in this case. The reduced wage and salary expense achieved through the incurrence of the severance costs will continue into the future. Therefore the Company should be allowed to recover the severance expense. I acknowledge that these particular severance expenses are "non-recurring" but that is why they are amortized over a multi-year period for ratemaking purposes. (IP Ex. 1.34, pp. 36-37)

CUB/AG contends that the five-year amortization period for the severance costs should be deemed to have started in 2000, when the related savings first began to be realized, and should continue through 2004. (CUB/AG Init. Br., pp. 15-16) CUB/AG's position should be rejected, as it would likely result in less than full recovery of the costs. (IP Ex. 1.34, p. 41) Although CUB/AG argue that IP began to realize the savings from the severance and early retirement programs in 2000, they ignore the fact that IP incurred wage and salary expense and related benefits and payroll tax expense for these employees in 2000 prior to their departure from the Company; these test year costs, however, have been removed in setting customers' rates in this case. (See IP Init. Br., pp. 52-53) Further, although the savings began in 2000, they will continue, and be reflected in the rates set in this and future cases, long after the amortization of the costs is completed. (IP Ex.1.34, p. 41)

Therefore, IP should have the opportunity for full recovery of the jurisdictional severance and early retirement costs through its delivery services rates.

c. Amortization of Expenses for Statutory Rulemakings

Staff opposes recovery of costs incurred by the Company in 1999 in connection with two statutorily-mandated rulemaking proceedings, the affiliate transactions rulemaking and the standards of conduct/functional separation rulemaking, even though the Commission allowed IP to recover costs for these proceedings in the 1999 DST Case. (Staff Init. Br., pp. 25-28) IP explained why it should be allowed to recover these costs in §II.C.3.c of its Initial Brief. Staff's position is premised on the erroneous contention that in the 1999 DST Case, the Commission was only allowing test year expenses for these two proceedings. (Staff Init. Br., p. 25) As shown at pages 58-59 of IP's Initial Brief, the costs of these proceedings allowed in the 1999 DST Case were <u>not</u> test year costs. Nor were they "known and measurable" changes to test year expenses (Staff Init. Br., p. 25), since the costs were by definition non-recurring. (IP Ex. 1.34, p. 33)

Staff relies on the Commission's rejection of a request for deferred accounting of Y2K expenses in a Citizens Utilities Company case, Docket 98-0895. (Staff Init. Br., pp. 27-28) However, that case is inapposite, as IP is not requesting deferred accounting of future costs, but only recovery of costs it has actually already incurred. Nor is the Company seeking to restate the amount recorded in Account 923 for 2000, as Staff implies. (Staff Init. Br., p. 26) Finally, Staff's contention that the Company's position constitutes retroactive ratemaking, because IP is seeking to recover a variance between actual expenses and those anticipated in the 1999 DST Case (Staff Init. Br., pp. 26-27), is incorrect. IP in fact anticipated these expenses at the time of the 1999 DST Case, but they were not included in setting rates because they had not yet been incurred. The Company is now simply seeking amortization and recovery of the additional actual expenditures of a specific type and purpose that the Commission, in the 1999 DST Case, deemed appropriate to allow. (IP Ex. 1.34, p. 34; IP Ex. 1.63, p. 26) Staff acknowledges that the expenses appear to be reasonable and made in the public interest. (Staff Init. Br., p. 28) Accordingly, the Company's proposed adjustment should be accepted for ratemaking purposes in this case.

d. Amortization of Y2K Expenses

Illinois Power fully addressed Staff's proposed disallowance of Y2K expenses in §II.C.3.d of its Initial Brief (pp. 59-60)

e. A&G Expenses Incurred in Distribution Operating Expenses/Charges from Dynegy

Illinois Power addressed Staff's and IIEC's arguments relating to the amount of A&G expense to be included in distribution operating expense in this case in responding to these parties' arguments concerning the amount of G&I plant to be included in distribution rate base. (See §II.B.3.c above; see also §II.B.3.c and §II.C.3.e of IP's Initial Brief) In addition to Staff's and IIEC's proposals to limit the amount of A&G expense in distribution operating expense to the amount allowed in the 1999 DST Case plus a percentage increase equal to the percentage increase requested in distribution O&M, CUB/AG contend that the entire test year expense for charges from Dynegy, recorded in Account 923, should be disallowed. (CUB/AG Init. Br., pp. 17-18) In addition, IIEC asserts that "IP did not produce any studies or analysis showing the economic advantage or cost savings associated with obtaining savings from Dynegy" and that "this Commission has no basis by which to judge whether or not the expenses paid by IP to Dynegy are reasonable and prudent from the perspective of ratepayers." (IIEC Init. Br., p. 10) These parties' contentions are without merit, and provide no basis for disallowing any portion of this component of the Company's test year expenses.

IP witness Carter presented a detailed breakdown of IP's billings from Dynegy and a detailed description of the services provided by Dynegy to IP. (IP Ex. 1.34, pp. 52-53; IP Exs. 1.54, 1.55) She also described reductions in its internal costs that the Company has been able to effectuate in the areas in which services and functions are now performed by Dynegy. (IP Ex. 1.34, pp. 50-51; IP Exs. 1.52, 1.53) In addition, she explained that IP is billed for the costs of the services provided by Dynegy in accordance with the SFA approved by the Commission in Docket 99-0114.[27] (IP Ex. 1.34, p. 53) The witnesses for CUB/AG and IIEC, Messrs. Effron and Phillips, made essentially no response to this detailed showing. Neither of them identified any particular items in the charges from Dynegy which were excessive, unreasonable or imprudent. Moreover, as CUB/AG point out, IP has certified to FERC that it believes the amount of its expense for services provided by Dynegy in 2000 is similar to the costs IP would have incurred for these services on a stand-alone basis.[28] (CUB/AG Init. Br., p. 17)

At a minimum, IP's detailed description of the billings from Dynegy, the services and functions provided by Dynegy, and the internal cost reductions IP has been able to achieve in

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[27] As noted at pp. 39-40 and 65 of IP's Initial Brief, Staff witness Hathhorn conducted a review of IP's billings from Dynegy under the SFA, and found only one error, which IP has accepted as an adjustment, reducing jurisdictional operating expenses by $1,035,000.

[28] It appears from CUB/AG's discussion at pp. 17-18 of their Initial Brief that they are under the misunderstanding that the SFA provides for the allocation throughout the "Dynegy consolidated group" of all costs incurred by any Dynegy entities. This is incorrect. As the SFA states, its purpose is limited to setting forth procedures and policies to govern the pricing of transactions between a Dynegy entity and IP, and the allocation of Dynegy A&G costs to all Dynegy entities, including IP. As Ms. Carter explained, the SFA does not provide for IP to allocate its A&G costs to other Dynegy subsidiaries except in connection with providing services and facilities to the other subsidiary. (Tr. 179-80; see Staff Cross Ex. 2)

areas where services and functions are now performed by Dynegy, were sufficient to shift the burden back to CUB/AG and IIEC to identify specific cost items that were excessive, unreasonable or imprudent. This they failed to do. Moreover, given IP's evidentiary demonstration (also unrebutted in any detail by CUB/AG, IIEC or Staff) of the overall reduction in the Company's electric A&G expense from 1997 to 2000 (see IP Init. Br., pp. 65-69), it is unreasonable for CUB/AG to focus solely on one category of A&G expense. CUB/AG's proposal to disallow all billings from Dynegy in Account 923 is unsupported and must be rejected.

f. Amortization of Accrual for Injuries and Damages

During the test year, Illinois Power, in accordance with Statement of Financial Accounting Standards No. 5 ("SFAS 5"), recorded an expense of $5.5 million as an accrual for damages in three pending claims matters. Because of the size of this accrual, IP is proposing to amortize it over three years for ratemaking purposes. (See IP Init. Br., pp. 71-72) CUB/AG, however, contend that no recovery of this expense should be allowed. CUB/AG claim that the inclusion in test year expenses of both actual claims paid and the amortization of this accrual constitutes "double recovery." (CUB/AG Init. Br., p. 20) CUB/AG's assertion is incorrect; IP is not receiving "double recovery" of anything. If, hypothetically, IP were to pay the claims that are the subject of the accrual in a future year that then became the test year in a future DST case, and the expense for the payment of the claims were included in the revenue requirement in that future case, then IP would be receiving "double recovery" of the expense incurred for these claims. However, IP has no intention of seeking "double recovery" of the expense for these claims in a future case, and even if the Company inadvertently attempted to do so, Staff and intervenors would undoubtedly catch the error.

CUB/AG state that the $5.5 million accrual is a "reserve for potential future claims." To be clear, the accrual relates to three occurrences that had already transpired as of December 2000, as to which the Company determined, in accordance with SFAS 5, that it has a liability exposure of $5.5 million in the aggregate. (IP Ex. 1.34, p. 66) However, the basic flaw in CUB/AG's reasoning is that, again in accordance with SFAS 5, IP was required to record this loss accrual as an expense in 2000. (Id.) CUB/AG witness Effron, a certified public accountant (GCI Ex. 2.0, p. 1), essentially agreed that the recording of an expense in these circumstances is required by Generally Accepted Accounting Principles, and he did not take issue with IP's determination that this particular expense should be recorded in 2000. (See Tr. 414-19) Thus, the $5.5 million loss accrual was as much an expense in the test year as the expense for claims actually paid to claimants in 2000. IP has properly recognized that the recording of the $5.5 million expense resulted in an abnormally high level of Injuries and Damages expense in 2000, and thus has proposed to amortize this item over three years. This is the appropriate ratemaking treatment under these circumstances. CUB/AG's proposed disallowance of the entire expense must be rejected.

g. Amortization Expense for Intangible Plant

CUB/AG contend that Illinois Power's amortization expense for intangible plant should be reduced. Their theory is that based on the balance of intangible plant at December 31, 2000, and the current annual amortization expense, the December 31, 2000, balance of intangible plant will be fully amortized approximately 2.4 years after the end of the test year and about 13 months after the rates set in this case go into effect, i.e., in approximately June

2003. (CUB/AG Init. Br., pp. 18-19) CUB/AG are apparently concerned that under this scenario, IP's DST rates would be recovering amortization expense for intangible plant for a period of time until DST rates are next re-set via a rate case, presumably in early 2005.

As Illinois Power witness Carter explained, CUB/AG's argument ignores the fact that IP is continuing to add intangible plant to its asset base. (IP Ex. 1.34, p. 70) CUB/AG claim, oddly, that this is "beside the point" (CUB/AG Init. Br., p. 19), but it is not. In fact, in this case, IP has identified $7,235,000 of post-December 31, 2000, additions to intangible plant (see Rev. IP Ex. 3.24, col. (35)); even under CUB/AG's analysis, the amortization of these additions would extend the point at which the unamortized balance of intangible plant reached zero to late 2004. And this assumes that IP does not place additional intangible plant into service after mid-2002, which of course is an unrealistic assumption.[29]

A more fundamental problem with CUB/AG's proposal is that it seeks to base an adjustment on events that will transpire in mid-2003. Certainly, between 2001 and 2005, IP will place additional distribution, general and intangible plant into service, will likely have to give wage and salary increases to its employees, and will be faced with a variety of other expense increases. CUB/AG is not proposing that DST rates be set in this case to recover the costs of additional investments and expenses that IP incurs in 2003; in fact, CUB/AG would be outraged if IP were to make such a proposal. Indeed, CUB/AG's proposal to adjust DST rates in this case for the anticipated (by CUB/AG) full amortization of the intangible plant balance in June 2003 stands in stark contrast to CUB/AG's attempt to limit post-test year

[29] Moreover, given that the amortization rate for intangible plant is based on a five-year useful life (see CUB/AG Init. Br., p. 19), intangible plant placed into service by IP in 1999 will not be fully amortized until some time in 2004, and intangible plant placed into service in 2000 will not be fully amortized until some time in 2005.

capital additions to those placed in service by June 2001. (See §II.B.3.a above) CUB/AG's proposal should be rejected.

h. Contributions to Community Organizations

Staff summarizes its proposed adjustment to remove the test year expense for contributions to certain community organizations, engaged primarily in economic development activities in their respective local communities and areas throughout IP's service territory, in §III.B.6 of its Initial Brief. IP addressed this proposed Staff adjustment in §II.C.3.h of its Initial Brief. For the reasons shown in that section, the payments in question are beneficial to customers and to the overall health of the service area, and should be included in the distribution revenue requirement as a reasonable business expense.

D. Cost of Capital

As stated in §II.D of IP's Initial Brief, for purposes of this case, the parties have agreed to an 8.69% rate of return on rate base, including an 11.89% rate of return on common equity. IP agrees with the summary in §IV of Staff's Initial Brief as to the evidentiary sources for the various components of the agreed rate of return. As Staff's summary indicates, some components of the agreed rate of return are based on evidence presented by the Company, while other components are based on evidence presented by Staff.

III. COST OF SERVICE AND RATE DESIGN

A. Cost of Service Studies

1. Overview of Embedded Cost of Service Studies/Use of IP's Embedded Cost of Service Studies for Revenue Allocation and Rate Design

It appears from the parties' initial briefs that, subject to resolution of a few specific issues discussed in §III.A.2 below, all parties accept the embedded cost of service study ("ECOSS") presented by Illinois Power in its rebuttal testimony for use as the basis for class revenue allocation in this case. IIEC expresses some complaints about the fact that IP submitted a substantially revised ECOSS in its rebuttal testimony, including that (according to IIEC) it was hard to review and verify the revised study, but IIEC nonetheless accepts the revised ECOSS as the basis for determining the allocation of the net revenue requirement to the customer classes.[30] (IIEC Init. Br., pp. 12-13) However, IIEC states that the ECOSS should not be used as the basis for setting individual rates and charges to the demand-metered class, and that instead all charges to this class should be increased on an equal percentage basis. (Id., pp. 13, 14, 20) In contrast, Staff contends that IP's proposed rate design (i.e., the individual charges that IP has proposed) does not conform closely enough to the results of the Company's revised ECOSS. (Staff Init. Br., p. 57)

Despite its general complaining, the only areas of the revised ECOSS to which IIEC directs anything resembling a specific criticism are that (1) the ECOSS for metering "was

[30] In support of its complaints, IIEC cites several criticisms of IP's ECOSS that were made by Staff witness Lazare. (IIEC Init. Br., p. 19) However, Staff expresses none of these criticisms in its Initial Brief. In addition, IIEC complains that in its direct case ECOSS, IP used incorrect and overstated values for revenues at current rates, thereby indicating a rate of return at current rates of 53.7%. (Id., p. 12) However, as IP cost of service witness Karen Althoff explained, and as IIEC's experts from Brubaker & Associates, Inc. were doubtless well aware, the error with respect to revenues at present rates did not affect the allocation of the distribution cost of service to the customer classes. (Tr. 517)

based on replacement cost allocations without valid reasons" (IIEC Init. Br., p. 18), and (2) "IP's allocation techniques concerning A&G expense and G&I plant are not sufficient given the magnitude of the costs to be recovered."[31] (Id., p. 13) The first of these criticisms is addressed in §III.A.2.b of IP's Initial Brief and §III.A.2.b of this Reply Brief, below. As to IIEC's second criticism, IIEC cites no record support for its assertion, nor does it explain what is "not sufficient" about IP's "allocation techniques", nor how they should have been improved. In fact, none of the cost of service witnesses in this case expressed any criticisms of, or identified any errors in, the manner in which Illinois Power allocated A&G expenses and G&I plant costs to the customer classes in the ECOSS. Moreover, as Illinois Power's cost of service witness, Karen Althoff, explained, the ECOSS was based on IP's proposed revenue requirement; she did not make any separate determination regarding the appropriateness of including any particular expense or capital items in the ECOSS. (IP Ex. 8.10, pp. 2-3) IIEC's criticisms are just a smokescreen.

The Commission should note that Staff and CUB/AG were able to review the ECOSS sufficiently to determine that it was acceptable for use for both revenue allocation and rate design purposes. It is not credible that IIEC, with the vast resources and expertise of Brubaker & Associates, Inc., at its disposal, was unable to review the ECOSS sufficiently to either find it acceptable for both revenue allocation and rate design purposes, or identify specific deficiencies and errors which, if corrected, would render the ECOSS acceptable.

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[31] IIEC also asserts that in IP's ECOSS, "the residential revenue requirement was taken from the 1999 DST case based on a 1997 test year." (IIEC Init. Br., p. 13) This is a misstatement of what was done in the ECOSS. The ECOSS in fact determined a residential distribution revenue requirement based on the 2000 test year. However, because there are no residential delivery services rates presently in effect, IP used the residential distribution revenue requirement from the ECOSS approved in the 1999 DST case, to represent the residential revenues under "present" rates. (IP Ex. 8.10, p. 3; IP Ex. 8.11, p. 1)

The conclusion the Commission should draw is that IIEC does not like the results that are generated by use of the ECOSS, but cannot find any specific changes to propose that would improve the outcome from IIEC's perspective – so it has instead raised a series of irrelevant side issues.

2. Cost of Service Study Issues

This section addresses specific issues concerning the Company's ECOSS for the distribution revenue requirement and its ECOSS for the meter revenue requirement that were raised in CUB/AG's and IIEC's initial briefs. Neither Staff nor MEC raised any issues concerning the revised ECOSS.

a. Allocation of Miscellaneous Revenues to the Customer Classes

CUB/AG take issue with the manner in which Illinois Power allocated revenues from equipment rentals to the customer classes. (CUB/AG Init. Br., pp. 23-24) IP addressed CUB/AG's contentions at pages 78-80 of the Company's Initial Brief. As explained there, CUB/AG's proposed allocation of miscellaneous revenues should be rejected. In addition, it appears that CUB/AG witness Smith re-allocated all miscellaneous revenues (i.e., forfeited discounts, service activation fee revenues, etc.) based on the amounts of distribution operating labor that were allocated to the customer classes, even though CUB/AG only raised an issue with respect to the Company's allocation of equipment rental revenues. (See CUB/AG Init. Br., pp. 23-24) This is an additional reason to reject CUB/AG's allocation of miscellaneous revenues.

b. Use of Replacement Costs to Allocate Costs of Meters and Service Drops to the Customer Classes

IIEC states, "[IP] Witness Althoff's cost of service study for metering indicated that it was based on replacement cost allocations without valid reasons", but IIEC does not provide any proposed alternative allocation. (IIEC Init. Br., p. 18) In fact, IP used replacement meter costs for each customer class to allocate the embedded costs of meters and services to the customer classes, as Ms. Althoff fully explained in her rebuttal and surrebuttal testimonies as well as in cross-examination. This issue is fully addressed in §III.A.2.b of IP's Initial Brief (pp. 80-81). As explained there, IP's use of replacement meter costs to allocate the embedded costs of meters and services was appropriate and in fact necessary, as well as being consistent with the method used in the 1999 DST Case. IIEC apparently believes that the embedded costs of meters and services should be allocated to the customer classes on the basis of the numbers of customers in each class. However, this approach would not take into account the much higher costs of the metering used to serve demand-metered customers as contrasted to residential and small use general service customers, and would over-allocate these costs to the residential class (Tr. 517-19), to the obvious benefit of the demand-metered class which includes the IIEC members.[32]

Accordingly, this component of Illinois Power's ECOSS should be accepted, and IIEC's criticism should be rejected. IIEC's criticism is just another invalid attempt by IIEC to cast doubt on the Company's revised ECOSS, whose results IIEC doesn't like.

[32] Moreover, although IIEC has complained about the method used to allocate meters and services costs to the customer classes, in fact in IP's ECOSS no costs for services in Account 369 were allocated to the high voltage customer class. (Tr. 519)

c. G&I Plant and A&G Expenses included in Revenue Requirement for Meters Subject to Unbundling

IIEC asserts that Illinois Power provided no support for the amounts of A&G expense and G&I plant allocated to the metering function in determining the revenue requirement for meters subject to unbundling. (IIEC Init. Br., p. 19) IIEC's assertion is wrong. As IP witness Ms. Althoff explained, G&I plant and A&G expense were allocated to the metering function on the same basis as approved by the Commission in the meter unbundling case, Docket 99-0013, namely, based on the relationship of meter service labor to total electric distribution labor. (Tr. 519-20) Meter service labor was 18.08% of total electric distribution labor; this percentage was therefore applied to electric distribution G&I plant and A&G expense to determine the amounts of G&I plant and A&G expense to be allocated to the metering function. (IP Ex. 8.10, pp. 9-10; IP Ex. 8.16, pp. 7-8; see IP Init. Br., pp. 81-82)

It is unclear why IIEC would be concerned about a high allocation of costs to the metering function and the resultant high metering charges. Given a specified overall distribution revenue requirement as determined by the Commission, the allocation of more costs to the metering function, and their recovery through the metering charges, means less of the revenue requirement needs to be recovered through other DST charges. However, in Docket 99-0013, the Commission decided to allow non-residential DST customers to obtain their metering from third party meter service providers. If Illinois Power charges higher metering charges (again, within the context of a fixed revenue requirement), this simply increases the ability of MSPs to enter the market and offer metering service to non-residential customers, such as the IIEC customers, at lower prices than IP's tariffed rates (see Tr. 713-

14) – thereby giving these customers opportunities to save on their overall energy delivery costs.

B. Allocation of the Distribution Revenue Requirement to the Customer Classes

It appears from the parties' initial briefs that all parties concur that the distribution revenue requirement should be allocated to the customer classes on the basis of IP's revised ECOSS (as the ECOSS may be further revised based on the resolution of the specific issues raised by IIEC and CUB/AG, as discussed above), with no deviations from cost of service for other considerations.

C. Delivery Services Tariff Rate Design

This section responds to the other parties' specific criticisms of Illinois Power's proposed rate design and individual proposed charges.

Illinois Power notes that Staff, in its Initial Brief, takes issue with (i) IP's proposed two-block delivery charges for residential and small use general service DST customers, (ii) IP's proposed implementation of a distribution capacity charge for demand-metered DST customers, and (iii) IP's proposed standby capacity requirement provision for customers with self-generation facilities that use delivery services for backup purposes. Each of these specific objections is discussed below. In addition, the introductory paragraphs in the section of Staff's Initial Brief on Rate Design contain this statement: "[T]he Company's proposed rates do not conform sufficiently to the results of the Company's cost of service study. Staff has addressed this shortcoming by proposing demand charges, facilities charges and unbundled meter charges that more closely cover the corresponding costs in the cost of service study. Staff's proposed rates offer the further advantage of adhering more closely to the underlying cost of service than IP's proposed rates. Thus, Staff's proposal is more consistent with the Commission's longstanding objective of cost-based rates." (Staff Init. Br., pp. 57-58) These statements are unaccompanied by any citations to the record; they are not further discussed or supported in the remainder of Staff's Initial Brief; and so far as IP can tell, they are not supported or derived from any of the prepared testimony of Staff's rate design witness, Peter Lazare.[33] And, IP believes these assertions are unfounded. Since these assertions in Staff's Initial Brief are totally unsupported, they should be ignored by the Commission; in any event, they provide nothing for IP to respond to in this Reply Brief. However, in its Initial Brief, IP has discussed certain of Staff's proposed charges that are set forth in Staff Exhibit 22.0.

1. <u>Residential DST Rate Design</u>

a. <u>Facilities Charges</u>

The parties taking a position on this topic are in agreement that the residential DST facilities charges should be set at $7.96 for single-family, single-phase installations, $5.96 for multi-family, single-phase installations, and $16.00 for three-phase service. These are the facilities charges that will be in effect in the bundled residential tariffs on and after May 1, 2002, reflecting implementation of the statutorily-mandated 5% residential rate reduction. (See IP Init. Br., pp. 82-83; CUB/AG Init. Br., pp. 24-25; Staff Init. Br., p. 57[34])

[33] Mr. Lazare's original exhibit that presented his proposed charges, Schedules 14.3-14.5 to Staff Ex. 14.0, was shown on cross-examination to be so riddled with errors that Mr. Lazare was forced at the conclusion of his cross-examination to request leave to file a new exhibit (which was granted). (Tr. 743-44, 784; see Staff Ex. 22.0) As a result, Mr. Lazare never really provided any testimony explaining the basis for his proposed charges.

[34] Staff does not explicitly address this topic in its Initial Brief, but refers to the Staff-proposed rates in Staff Ex. 22.0, which shows the same residential DST facilities charges proposed by IP and CUB/AG.

b. <u>Delivery Charge</u>

Illinois Power and CUB/AG agree that the residential DST delivery charge established in this case should have a declining block structure, with the first block set at 300 kWh per month. (IP Init. Br., p. 83; CUB/AG Init. Br., p. 28) Staff disagrees and contends that the residential DST delivery charges should be flat. (Staff Init. Br., pp. 58-60) Staff's position is premised on the arguments that (1) secondary facilities costs should be recovered over all kWh of usage, not in an initial block, and (2) a flat delivery charge will be higher than the tailblock in a two-block delivery charge, and therefore will provide greater incentive to conservation of electricity. (Id.) Staff does not take into account a third, important factor relied on by the IP and CUB/AG witnesses, namely, rate continuity: a two-block delivery charge with the first block at 300 kWh will provide the same structure as the energy charge in the principal existing residential bundled tariff, Service Classification ("SC") 2, thereby providing rate continuity for these customers as they consider switching from bundled service to delivery services. (IP Ex. 6.6, p. 7; See GCI Ex. 1, p. 14; Tr. 901) Although rate continuity between bundled rates and DST rates was an important consideration for Staff in other areas of rate design, such as the residential DST facilities charge (as to which Staff agrees with IP and CUB/AG that the charges should be set equal to the charges in the bundled residential tariffs), Staff apparently chose to ignore rate continuity as a consideration in formulating its position on the residential DST delivery charge.

Staff's position that secondary facilities costs should be recovered over all kWhs of delivery ignores two important facts: First, secondary facilities costs are incurred as a function of both the number of customers and the customers' expected maximum demands on the system; however, the secondary costs for residential customers predominantly consist of the costs to connect the customer to the system, regardless of the customer's load. (IP Ex. 6.14, p. 8) The secondary system costs are heavily weighted towards a function of the customer being connected to the system; the demand or usage-sensitive portion of secondary facilities costs is relatively small. Since secondary facilities costs are largely a function of the customer being connected to the system, it is appropriate to collect these costs through a front block in the delivery charge.[35] (See IP Init. Br., p. 84)

Second, there is some usage-sensitive component to the incurrence of secondary facilities costs (i.e., larger-use customers tend to also have larger demands, and thus at some point will require larger-sized secondary facilities); however, although total secondary facilities costs per customer tend to increase as the size (kWh used per month) of the customer increases, the secondary facilities cost per kWh decreases as customer size and usage increase. (IP Ex. 6.6, pp. 8-9) Thus, using a flat delivery charge (and thereby recovering the same amount of secondary facilities costs in each kWh of usage) would be discriminatory to larger-use customers, and would shift cost recovery from smaller-use to larger-use customers. (IP Ex. 6.14, pp. 7-8) Staff's arguments take account of neither of these factors.[36]

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[35] Although supporting the two-block rate structure for purposes of this case, CUB/AG note that the recovery of secondary facilities costs in the first 300 kWh of the delivery charge causes the two-block structure to operate more like a customer charge. (CUB/AG Init. Br., p. 26) However, since secondary facilities costs are largely a function of connecting the customer to the system, this is not inappropriate. (See IP Ex. 6.6, p. 9) Moreover, since 80% of IP's residential customers use at least 300 kWh per month (IP Ex. 6.1, p. 12), most customers will pay for their costs of secondary facilities each month through IP's proposed structure. In fact, only the smallest-use residential customers (those using fewer than 300 kWh per month) would fail to pay for their secondary facilities costs.

[36] CUB/AG's comments about the recovery of secondary facilities costs also ignore the fact that the most significant driver of these costs is the need to connect the customer to the system. (See CUB/AG Init. Br., pp. 26-28)

To illustrate the above points, IP rate design witness Leonard Jones presented Rev. IP Exhibit 6.12, which shows the total secondary facilities costs per customer, and the secondary facilities costs per kWh, to serve a customer using 300 kWh per month and a customer using 3,000 kWh per month. While the exhibit obviously depicts hypothetical customers, the Company believes it is representative of the relevant equipment sizes and related costs needed to serve the two sizes of customers. As the exhibit shows, the <u>total</u> cost of secondary facilities to serve a group of six 3,000 kWh/month customers ($3,948, or $657.98 per customer) is higher than the total cost of secondary facilities to serve a group of six 300 kWh/month customers ($2,281, or $380.10 per customer). However, even with the higher total secondary facilities costs for the larger customers, the annual cost per kWh to serve the 3,000 kWh /month customers (0.21 cents per kWh) is considerably lower than the annual cost per kWh to serve the 300 kWh/month customers (1.22 cents per kWh). Thus, a flat residential DST delivery charge, as proposed by Staff, would over-recover these costs from larger-use customers and under-recover them from smaller-use customers.

It is also noteworthy from Rev. IP Exhibit 6.12 that although the monthly usage increases ten-fold between the two groups of hypothetical customers, the total cost of secondary facilities needed to serve the group of 3,000 kWh/month customers is less than two times the total cost of the secondary facilities needed to serve the group of 300 kWh/month customers. For example, the installed cost of the transformer needed to serve the circuit (the single most expensive piece of equipment among the secondary facilities (Tr. 905)) only increases from $1,049 to serve the group of 300 kWh/month customers, to $1,616 to serve the group of 3,000 kWh/month customers. This illustrates that the most significant driver of the cost of secondary distribution facilities is the need to connect the customer to the system, and not the size of the customer's maximum demand or monthly usage. Yet contrary to this cost data, under Staff's proposal, the 3,000 kWh/month customer would pay ten times as much in secondary facilities costs as the 300 kWh/month customer. (IP Ex. 6.14, p. 7)

CUB/AG offered several criticisms of Rev. IP Ex. 6.12, such that it is "very specific" (CUB/AG Init. Br., pp. 30-31); however, they did not offer an alternative exhibit or hypothetical that depicts the opposite conclusion. Nor were CUB/AG able to achieve this result by changing the assumptions in the exhibit.[37] For example, even if one assumes that the same size- and cost- secondary facilities would be required to serve a group of six 1,000 kWh/month customers as the exhibit shows are needed to serve six 3,000 kWh/month customers, the cost per kWh of secondary facilities for the group of larger customers would still be considerably lower than the cost per kWh of secondary facilities needed to serve the group of smaller (300 kWh/month) customers. (Tr. 873-74, 906) As IP witness Jones explained, even if the exhibit were revised to use "average" or "typical" secondary facilities designs, it would still lead to the same conclusions: the cost of secondary voltage systems is not significantly driven by demand, and the total cost of serving various sized customer groups is not significantly different. (IP Ex. 6.14, p. 9)

With respect to Staff's second reason for proposing a flat residential DST delivery charge, i.e., to encourage conservation, Illinois Power continues to question whether encouraging conservation is an appropriate objective in setting rates for a delivery services

[37] The specific customer sizes (300 kWh/month and 3,000 kWh/month) used in Rev. IP Ex. 6.12 were chosen based on a statement in Staff witness Lazare's direct testimony that "it would be reasonable to assume that a customer using 3,000 kWh per month would require larger secondary facilities than a customer using 300 kWhs per month." (Staff Ex. 5.0, p. 38; see IP Ex. 6.14, pp. 6, 8)

provider (IP) that are for delivery only and do not encompass the provision of electric energy. Certainly, the DST rates set for Illinois Power in this case will not include any costs of the electricity consumed by the delivery services customer. Encouraging conservation through rates that reflect the additional costs that will be incurred if one more kWh is consumed, or saved if one less kWh is consumed, is an appropriate objective; however, raising a tariffed charge simply because customers will use less if the rates are higher, without regard to the underlying costs, is not an appropriate objective. (See IP Init. Br., p. 84, n. 49) Since the DST rates that Illinois Power will charge customers for delivery services do not recover any costs of the electricity consumed by the customer, the necessary link between cost incurrence (or savings) and customer consumption decisions that Staff posits is missing.[38]

Staff states that IP witness Jones acknowledged that if delivery services customers consumed less electricity, less electricity will have to be produced and the impact on the environment will be lessened. (Staff Init. Br., p. 60) That is a better characterization of Staff's cross-examination questions than of Mr. Jones' answers:

> Q. Certainly. The more that delivery services customers demand electricity, the more electricity has to be produced to meet that demand and, thus, the greater will be the impact on the environment, is that correct?
>
> A. I would think as a general rule the more electricity that is produced, the more of an impact there would be on the environment.
>
> .

[38] At page 28 of their Initial Brief, CUB/AG include a quote from the "October 2001 Report of the Illinois Energy Cabinet", to the effect that declining block rates encourage higher energy use. Neither this quote nor the report are in the record, and CUB/AG did not request that administrative notice be taken of the report (putting aside the question of whether taking notice would be justified). Therefore, the Commission should disregard this quote and any argument based on it. Moreover, it would appear that the quote is referring to declining block energy charges (both electric and gas), not declining block delivery charges.

Q. Conversely, if delivery services customers consumed less electricity, less electricity will have to be produced and the impact on the environment will be lessened, is that correct?

A. To the extent there is an impact by generating the electricity, yes.

Q. And if the impact on the environment is lessened, we all benefit, including delivery services ratepayers, is that correct?

A. I don't know. (Tr. 818-19)

In any event, this testimony still begs the question as to whether it is appropriate to consider encouraging conservation as a factor in setting DST rates, which do not recover any costs of generating electricity. What Staff's invocation of "conservation" as a criterion in setting delivery services rates that recover no energy costs really shows is that even though electricity generation has been unbundled from electricity delivery, Staff does not accept that it can no longer regulate by social objectives as it could when the entire, vertically-integrated electricity production and delivery system was under monopoly regulation.[39]

With respect to the differential between the first block and the tailblock of the two-block residential DST delivery charge, IP maintains that the differential should be set at 1.4 cents, while CUB/AG argue that the differential should be set at 0.8 cents. (IP Init. Br., p. 85; CUB/AG Init. Br., p. 29) The methodological difference between the parties' positions is that CUB/AG would set the differential equal, on a year-round basis, to the <u>summer</u> differential between the first and second energy charge blocks in residential bundled SC 2, whereas IP would set the differential at the load-weighted average of the summer (0.8

[39] Illinois Power submits that the question of whether reduced electricity use benefits the environment is much more complex than Staff's simplistic cross-examination of Mr. Jones would suggest. If consumers use less electricity they may as a result use more of some other form of energy whose production and usage has less desirable environmental impacts. In addressing this question there are also issues relating to time of use and to the sources of generation employed.

cents/kWh) and winter (1.76 cents/kWh) differentials between the first and second blocks in SC 2, thereby providing a greater degree of rate continuity to the current residential bundled rates on a year-round basis. (IP Ex. 6.6, p. 6) IP's proposed differential is actually closer than is CUB/AG's proposed differential to the original proposal of CUB/AG witness Smith, which was "the price differential between the block rates, should be the same in the delivery service rate and the bundled rates." (GCI Ex. 1, p. 20; see IP Ex. 6.14, p. 5) In addition, as described at pages 85-86 of IP's Initial Brief, the combination of the agreed residential DST facilities charges and IP's proposed delivery charges, taken together, appropriately recovers the cost of service. CUB/AG's proposed delivery charge, in contrast, would provide a differential equal to that faced by residential bundled service customers only four months of the year, and would be inferior to the Company's proposal on both rate continuity and overall cost recovery grounds.

In summary, Illinois Power's proposed residential DST delivery charge rate design best promotes the twin objectives of achieving proper cost recovery and maintaining rate continuity with the residential bundled rates. IP's proposed rate design for the residential DST delivery charge should be adopted rather than the proposals of Staff and CUB/AG.

2. Small Use General Service Rate Design

a. Facilities Charges

Illinois Power explained why its proposed facilities charges for the general service small use class should be adopted at pages 86-87 of its Initial Brief. No other parties specifically addressed these facilities charges in their initial briefs. Staff has proposed different facilities charges than the Company for this class, on Staff Exhibit 22.0, but does not discuss its proposed facilities charges in its Initial Brief. In any event, Illinois Power's

Initial Brief (§III.C.2.a) explains why IP's proposed facilities charges for the small use general service class are preferable to the charges proposed on Staff Exhibit 22.0, which Staff has not specifically justified in either its testimony or its brief. Accordingly, IP's proposed facilities charges for the small use general service class should be adopted.

b. Delivery Charge

The superiority of Illinois Power's proposed delivery charges for small use general service customers and unmetered service customers over Staff witness Lazare's proposed charges was demonstrated in §III.C.2.b of IP's Initial Brief. Staff proposes a flat DST delivery charge for small use general service customers, which Staff discusses in §V.A.1 of its Initial Brief together with its proposed flat delivery charge for the residential DST customers.[40] The issues concerning adoption of a two-block (as proposed by IP) versus a flat delivery charge for the small use general service rate class are essentially the same as for the residential DST delivery charge. In addition to the reasons for adopting IP's proposed delivery charge rate design for this class, as described in §III.C.2.b of IP's Initial Brief, rate continuity should also be considered. While the delivery charge in present SC 110 for the small use general service customers is flat, the energy charge in the bundled rate for small use general service customers, SC 10, has a declining block structure, not a flat structure. In light of the fact that very few small use general service customers have switched to delivery services at this time, maintaining rate continuity from the current bundled rate to the delivery service rate for this class is a more important consideration than maintaining rate continuity between the delivery charge currently in SC 110 for this class and the delivery charge adopted in this case. (Tr. 806-07, 871-72) Thus, IP's rate design for this component is also

[40] Staff does not, however, provide any support in its Initial Brief for the proposed delivery charge for unmetered general service customers that is shown on Staff Ex. 22.0.

superior to Staff's rate design on rate continuity grounds. IP's proposed rate design for the delivery charge for small use general service customers should be adopted.

3. Demand-Metered DST Rate Design

a. Facilities Charges

Illinois Power described and justified its proposed facilities charges for the demand-metered class in §III.C.3.a of its Initial Brief. IP showed that its proposed facilities charges for this class are superior to those proposed by Staff witness Lazare in Staff Exhibit 22.0 because IP's facilities charges are closer to cost of service, represent a considered step in moving towards fully cost-based facilities charges for this class, and provide a greater degree of rate continuity. Staff has not attempted to explain or justify Mr. Lazare's proposed facilities charges in its Initial Brief.

IIEC argues that facilities charges, metering charges and demand charges should all be increased on an equal percentage basis for the demand-metered class. (IIEC Init. Br., pp. 14, 18-20) IIEC provides no specific cost-of-service basis for its proposal; rather, IIEC's position is premised solely on its general (and unfounded) complaints about IP's ECOSS. (See §III.A above) However, the current DST rates for demand-metered customers are out of alignment with the underlying cost of service, and produce a subsidy for the large demand-metered customers. IP's proposed rate design will move the rates closer to cost of service. (IP Ex. 6.14, p. 14) IIEC's equal percentage increase approach should be rejected in favor of IP's proposed facilities charges, which as noted above, were specifically developed based on cost of service and rate continuity considerations.

b. Demand Charges and Distribution Capacity Charges

i. Demand Charges

Illinois Power explained and justified its proposed rate design for demand charges and distribution capacity charges for the demand-metered class in §III.C.3.b of its Initial Brief. Under IP's proposal, demand charges will recover the costs of high-voltage facilities, which are designed primarily based on the diversity of several customers' loads, and will be billed based on the customer's maximum monthly demand (the same basis as in current SC 110).[41] (IP Ex. 6.1, p. 16) Staff does not specifically discuss rate design for demand charges in its Initial Brief (although Staff does oppose IP's proposal to implement a separate distribution capacity charge, as discussed below), but Staff witness Lazare found IP's demand charge methodology to be generally acceptable. (See Staff Ex. 14.0, p. 22)

ii. Equal Percentage Increase to All Charges for Demand-Metered General Service

As noted above in the discussion of facilities charges for this class (§III.C.3.a), IIEC proposes that facilities charges, metering charges and demand charges for the demand-metered class should all be increased on an equal percentage basis. As with the facilities charges, IIEC provides no specific cost-of-service basis for this proposal. To the extent IIEC's proposal is based on its complaints about IP's ECOSS, its concerns were discussed in §III.A.2 above. As shown there, IIEC's complaints about the ECOSS do not warrant abandoning the ECOSS as a source of information to use in setting specific rates and charges, and adopting instead an arbitrary across-the-board increase for the charges to the demand-metered DST class. As noted above in the discussion of facilities charges for the demand-

[41] In designing the demand charges, IP used the revenue that will be produced by transformation charges to reduce the revenue necessary to be collected through demand charges at each voltage level. (IP Ex. 6.6, p. 13)

metered class, the current DST rates for demand-metered customers are out of alignment with the underlying cost of service, and produce a subsidy for the large demand-metered customers. IP's proposed rate design will move the rates closer to cost of service. (IP Ex. 6.14, p. 14) IIEC's equal percentage increase approach should be rejected in favor of the specific cost-based demand charges proposed by IP.

Apparently as part of its argument in support of its proposal that all facilities, metering and demand charges for the demand-metered class should be increased on an equal percentage basis, but in a different section of its brief (the section entitled "The State of Retail Competition in The IP Service Territory"), IIEC asserts that "IP has a direct financial incentive to artificially assign more of the revenue requirement increase to large customers than to small customers."[42] (IIEC Init. Br., p. 4) The basis for this assertion, according to IIEC, is that increased DST rates to small customers will be offset by decreases in those customers' transition charges ("TC"), producing no net revenue increase for IP, but "many of IP's largest customers have a zero transition charge", and therefore increases in these customers' DST rates will not be offset by decreases in their TCs. (Id.) IIEC's argument should be rejected, for at least two reasons.

First, most of the IP customers over 1 MW would pay a TC if they switched to delivery services today. As IP witness Leonard Jones explained:

> Of the customers still served under bundled rates, all SC 21 and SC 24 customers, if eligible to switch, would pay a TC if they switched by the end of October. . . Thus, to the extent that these customers were to switch to delivery service, the delivery service rate design impact will be absorbed by the customer's transition charge. In other words, the impact of the delivery service rate change will not be felt by the customer, or the Company, in terms of total revenue paid and collected. Further, if a customer does not have a TC, this is because the customer's bundled service rate is near or below the cost

[42] Of course, as IIEC witness Stephens testified, IIEC has direct financial incentive to assign more of the revenue requirement increase to customers who are not IIEC members. (Tr. 666)

> the customer would incur for power in the competitive market (i.e., what the competitive market could offer the customer.) (IP Ex. 6.6, p. 14)[43]

Thus, the rate design changes and resultant increases in facilities, metering and demand charges that IP proposes for the demand-metered class are unlikely to present a disincentive to demand-metered customers switching from bundled tariffs to delivery services.

Second, as noted above, the Company's proposed charges for the demand-metered class are intended to move these rate elements closer to (although not all the way to) cost of service. In the long run, consistent with this Commission's long-standing policy to base rates on cost of service, eligible customers are more likely to choose to use delivery services if DST rates are based on cost of service rather than on arbitrary across-the-board increases. Further, if a customer analyzes cost-based DST rates and chooses not to take delivery services, the customer will have made its decision based on appropriate price signals (even if the cost-based DST rate is higher than a DST rate set on some arbitrary basis). In summary, IP's proposed rate design for the demand-metered DST class is more likely to promote and support the proper development of the retail competitive market in IP's service area than are rates reflecting arbitrary equal-percentage increases as proposed by IIEC.

iii. <u>Distribution Capacity Charges</u>

Staff opposes IP's proposal to establish a separate distribution demand charge for demand-metered customers served at supply line voltages of 12.47 kV and below, that would

[43] Further, if the market values that are determined under IP's Rider MVI tariff for use in May 2002, when the DST rates set in this case go into effect, are the same as the market values in effect for the period of October 29 to December 30, 2001, all of the customers currently served on SC 21 and SC 24 would have a positive (non-zero) TC if they switched to delivery services. (Tr. 874-76)

be billed based on the customer's maximum demand in the preceding 12 months.[44] (Staff Init. Br., pp. 60-62) Staff's opposition is based on these contentions: (1) billing the distribution capacity charge on the basis of the highest demand in the prior 12 months would diminish the need to control monthly peaks; (2) there is not evidence of a lack of diversity in these customers' use of low voltage facilities (the costs of which the distribution capacity charge is intended to recover); (3) the Commission has a "long-standing policy" against demand ratchets; and (4) although IP's bundled tariffs contain a distribution capacity charge that is billed on the basis of the highest demand in the prior 12 months, the current DSTs do not include such a charge. (Id.)

None of these contentions support Staff's position, or warrant rejection of the proposed distribution capacity charge. Illinois Power addressed Staff's contentions (1), (3) and (4) in §III.C.3.b of its Initial Brief (pp. 90-91) and showed them to be without merit. In connection with contention (4), Staff apparently believes that if the Company did not propose a particular rate design component in its initial (1999) DST case (where many, many novel issues had to be addressed), the Company is forever precluded from proposing that rate design component for its DST rates.[45] (See Staff Init. Br., pp. 61-62) Staff also dismisses the fact that IP's bundled rates for demand-metered customers contain a distribution capacity charge that is billed on the basis of the customer's highest demand in the prior 12 months, on the grounds that IP's current bundled tariffs were approved almost a decade ago. (Id., p. 62)

[44] The distribution capacity charge is intended to recover the costs of local low-voltage facilities. (IP Ex. 6.1, p. 15) Under IP's proposed rate design there would continue to be a demand charge for the demand-metered class, to recover the cost of high-voltage facilities, which will be billed on the basis of the customer's maximum monthly demands. (Id., p. 16) Thus, revenues formerly collected through the single demand charge would now be collected through the combination of these charges.

[45] Similar thinking by Staff is evidenced in its opposition to IP's proposed implementation of a two-step declining block delivery charge in SC 110 for small use general service customers.

However, while the fact that IP's current bundled rates were approved almost a decade ago may mean that they no longer adequately recover IP's revenue requirement, this should not affect the validity of the rate design.

As to the Commission's so-called "long-standing" opposition to demand ratchets (which apparently is not that "long-standing", as it did not result in rejection of IP's distribution capacity charge for its bundled tariffs in 1992), as IP showed in its Initial Brief (p. 91), in cases where the Commission has rejected the use of demand ratchets in DST rates, the utility was attempting to recover the entire revenue requirement through the demand-ratchet rate. That is not the case with IP's proposal in this case. Further, IP's bundled tariffs are expected to be in effect for at least three more years (until at least early 2005); given the still relatively early stage of development of the competitive retail power supply market and of the availability of delivery services to non-residential customers (may of whom first became eligible on January 1, 2001), the Company believes that maintaining continuity between current bundled rates and DST rates is a more important objective than inflexibly maintaining the same rate design embodied in the current DST rates that were approved in the 1999 DST Case.

Staff's contention (2) relating to the level of diversity among customers using low voltage facilities ignores the fact that it is annual customer peak demand that drives distribution investment – once the customer establishes a maximum demand on the system, the distribution system must be ready to serve that level of demand in the future. The customer's ongoing monthly demands are of little consequence in this regard once the customer has established a maximum demand on the local distribution circuit. (IP Ex. 6.6, pp. 18-19) Further, while it is possible that some demand-metered customers on the same distribution circuit may peak at different times, it is far more common for customers on a primary voltage circuit to behave similarly in this regard. In fact, most of IP's demand-metered customers served on the primary voltage system are commercial customers whose peaks are driven primarily by air-conditioning load. (IP Ex. 6.14, p. 13) Finally, moving to the distribution capacity charge as proposed by the Company will reduce the extent to which higher load factor customers subsidize lower load factor customers, as they do under the present rate structure which includes only a demand charge billed on the basis of maximum monthly demands. (IP Ex. 6.6, p. 19; IP Ex. 6.14, p. 13)

c. <u>Reactive Demand Charge</u>

As stated at page 91 of IP's Initial Brief, the parties interested in this issue (IP, IIEC and Staff) have agreed that for purposes of this case, the reactive demand charge should be set at 13 cents per kVar.

d. <u>Transformation Charges</u>

As discussed at pages 92-93 of IP's Initial Brief, IP is not proposing any changes to the transformation charges currently in effect in SC 110: 50 cents per kW of distribution capacity for customers with distribution capacities below 3 MW, and 75 cents per kW of distribution capacity for customers with distribution capacities of 3 MW or more. IIEC, however, takes issue with the existence in current SC 110 of a higher transformation charge for customers with distribution capacities of 3 MW and above than for those with distribution capacities below 3 MW. IIEC proposes either that the transformation charge for customers 3 MW and above be reduced to 50 cents per kW, or, alternatively, that the transformation charge be set at 75 cents per kW for all customers. As IIEC notes, the latter approach would be consistent with IP's bundled tariffs, in which the transformation charge is 75 cents per kW for all customers. (IIEC Init. Br., p. 18) However, the record supports leaving the SC 110 transformation charges at their current values.[46]

IIEC objects that IP has justified the above-3 MW transformation charge by the "marginal" cost of the relevant facilities. (To be clear, the above-3 MW transformation charge is supported by the current costs of installing transformation facilities and equipment for such customers, plus applicable expenses, over a range of installations. (IP Ex. 6.6, p. 16)) Although acknowledging that customers have the option to install or lease their own transformation facilities, IIEC contends that the transformation charge must be based on embedded costs because "transformation service has not been declared competitive." (IIEC Init. Br., p. 16) IIEC's assertion is a red herring. If transformation service were "declared competitive" by the Commission pursuant to PUA §16-113, IP would not be obligated to offer this service as a tariffed, regulated service at all, nor be constrained to any specific cost basis for its charges – embedded, marginal or other – but only by what the market would bear (if, indeed, IP were to continue offering transformation service at all, which it would not be required to do).

What is relevant here is that, even though transformation service has not been "declared competitive", demand-metered customers have the option of obtaining their transformation requirements through installation of their own facilities, leasing facilities from

[46] Staff Ex. 22.0, Sched. 14.5 Rev., indicates that Staff proposes to essentially maintain the current transformation charges for customers with distribution capacities below 3 MW and 3 MW and above, although Staff's proposed charges are slightly different from the current charges, at 53.1 cents per kW and 79.7 cents per kW, respectively. Apparently these slight changes to the current charges were necessary in order to recover the total class revenue requirement in light of Staff's changes to others of IP's proposed charges. IP does call to the Commission's attention that IP has not proposed any changes to the transformation charges in its tariff filing in this case. Therefore, if the Commission were to accept Mr. Lazare's rates, the Commission would be increasing rates that the utility has not filed to increase.

IP or leasing facilities from a third party. Thus, basing the transformation charge on the current cost to IP to install transformation facilities for a customer reflects not only the economic decision the customer faces (IP Ex. 6.6, p. 16), but also the costs the customer imposes on IP if it decides to obtain tariffed transformation service from the Company. If IP were required to provide tariffed transformation service to above-3 MW customers who elect to obtain that service from the Company, at a price below the cost of installing the required facilities, as IIEC suggests (and correspondingly, below the cost to the customer of obtaining the facilities from other sources), IP would have to recover the resulting revenue deficiency through other charges. As a result, other customers would be subsidizing the above-3 MW customer who elects to obtain the service from IP. (IP Ex. 6.6, p. 17) The Commission should not countenance such a result given that these customers have competitive options for transformation facilities and service.

In fact, with both the bundled and DST transformation charge for customers with distribution capacities of 3 MW and above already set at 75 cents per kW, 57 of the 73 customers 3 MW and above on the IP system already rent or own their transformation facilities, rather than take the tariffed service from the Company. (IP Ex. 6.6, p. 16) Obviously, these customers have found the other options more attractive, for price or other reasons. The Commission should be wary of lowering the current tariffed rate and thereby risking incenting these customers to take subsidized tariffed transformation service. Further, if the transformation charge is left at the current level of 75 cents per kW in both the bundled tariffs and the DST, these customers will face the same price whether they elect to switch to delivery services or remain on bundled service.

IIEC contends that the cost information in IP Exhibit 6.10, Schedule 2, Item 4, does not support a 75 cent per kW transformation charge for customers 3 MW and above. (IIEC Init. Br., pp. 16-18) As an initial matter, IIEC cites the original version of this schedule at page 18 of its Initial Brief, not the corrected version. The average of the cost per kW of the five recent transformation installations for customers 3 MW and above shown on Revised IP Exhibit 6.10, Schedule 2, Item 4 is 63 cents, not 55 cents.[47] (The average cost per kW of facilities for customers below 3 MW as shown on this schedule is 47 cents, consistent with the current transformation charge of 50 cents per kW for these customers.) More importantly, by focusing on the average cost of the installations for the above-3 MW customers, IIEC is missing the point of the exhibit, which is, as Mr. Jones explained, to show that a charge of 75 cents per kW is "within the range of costs of recently installed facilities."[48] (IP Ex. 6.6, p. 16) It is the range of costs of transformation installations for these larger customers, not the average, that is important, because of the differing facilities that different customers above 3 MW may require depending upon their particular service configuration.[49] (Id., p. 17; IP Ex. 6.14, pp. 15-16) Moreover, if any above-3 MW customer believes that the charge of 75 cents per kW for the tariffed service is greater than the cost of

[47] IIEC asserts that one of the five installations for customers 3 MW and above shown on this schedule was actually for a customer smaller than 3 MW. (IIEC Init. Br., p. 16) IIEC is apparently referring to the second installation listed which was for a customer whose distribution capacity is 2.975 MW.

[48] The range of costs per kW of the five installations is from 43 cents per kW to 97 cents per kW. (Rev. IP Ex. 6.10, Sched. 2, Item 4)

[49] For example, customers above 3 MW typically require individual substations to transform their power; these substation costs can vary considerably from customer to customer. As another example of differences, some customers may require additional fault protection. Mr. Jones described other differences that may arise in individual installations for customers above 3 MW. (IP Ex. 6.6, p. 17)

the specific transformation facilities needed by that customer, the customer has the option of owning or leasing the specific facilities it needs, at lower cost than the tariffed charge.

IIEC's final attempt to confuse this matter is to note that the embedded cost of transformation on the IP system is $1.12 per kW, and that in the 1999 DST Case, Mr. Jones testified that the embedded cost of transformation is 42 cents per kW.[50] (IIEC Init. Br., p. 18) However, the $1.12 per kW figure is the embedded cost of tranformation throughout IP's entire system, including the cost of transformation equipment that transforms power from the transmission or subtransmission voltage all the way down to the service level required by the customer, including residential and small use general service customers. (IP Ex. 6.14, p. 16) Thus, this system-wide average figure is not really relevant to determining the cost of transformation needed to reduce power from the supply line voltage serving a 3 MW and above customer to the service voltage level that customer requires, which is the basis for the transformation charge. (Id., pp. 16-17) With respect to the 42 cents per kW figure cited from the 1999 DST Case, that figure was the embedded cost only for line transformers installed on the IP system. The $1.12 per kW figure is the embedded cost of both line transformers and substations, and is the more appropriate representation of the cost of transformation on the IP system. (Tr. 877-78) In any event, as noted above, neither of these system-wide cost figures is relevant to determining the appropriate charge for transformation specifically installed to serve demand-metered customers 3 MW and above.

Finally, the Commission should wonder why IIEC is concerned about the current SC 110 transformation charge for customers with distribution capacities 3 MW and above. It is the same charge as in the bundled tariffs, so it produces no incentive or disincentive towards

[50] IIEC never explains why it thinks the $1.12/kW figure is important. IIEC has not proposed that the transformation charges be increased to this level.

switching to delivery services. If it were reduced, the revenue not recovered from the transformation charge would have to be recovered through higher demand charges to all demand-metered customers, which would seem to be detrimental to the interests of the greater number of customers. Further, if the 75 cents per kW charge is in fact too high (by whatever measure) based on the facilities required by a particular customer, that customer has the option of owning or leasing its necessary transformation facilities, at lower cost. In summary, IIEC's position concerning the transformation charge for customers 3 MW and larger is not only unsupported by the record, but may be contrary to IIEC's own best interests. The Commission should leave the transformation charges in SC 110 at their current levels.

e. Standby Capacity Requirement for Self-Generation Customers Using Delivery Services for Standby Purposes

Staff and IIEC take issue with Illinois Power's proposed standby capacity requirement ("SCR") provision for customers with self-generation facilities ("SG") that elect to use a RES, and therefore IP's delivery services as well, as their source of backup or standby power at those times that the customer's SG facility is not operating or is operating at a reduced level.[51] (Staff Init. Br., pp. 63-91; IIEC Init. Br., pp. 21-24) Staff's and IIEC's arguments that are based on the evidence they submitted (in contrast to the arguments that

[51] Staff's description of IP's proposal at the top of page 64 of Staff's Initial Brief is incorrect because it essentially describes IP's SCR proposal in its direct case filing, and does not reflect the substantial modifications IP made to the SCR provisions in rebuttal in response to comments from Staff and IIEC. An accurate description of IP's proposal is set forth at pages 93-95 of IP's Initial Brief. To the extent that Staff's Initial Brief is responding to IP's original proposal, it is misdirected and irrelevant.

Staff has concocted for the first time in its Initial Brief, without any basis in the record) were fully addressed in §III.C.3.e of IP's Initial Brief (pp. 93-99), and shown to be without merit.[52]

Staff and IIEC argue that the SCR provision is discriminatory and punitive to SG customers, in that (they contend) it requires an SG customer desiring to use a RES and delivery services for standby purposes to accurately estimate the customer's standby capacity requirement or face the possibility of being billed three times the applicable demand charges for a portion of the customer's demand that exceeds the SCR, in the month in which the SCR is exceeded.[53] According to Staff, the SCR provision will give the SG customer a strong incentive to "overestimate" its standby delivery requirement. (Staff Init. Br., p. 87) However, the argument presented by IIEC shows that this is really not a serious risk to the

[52] IP filed a motion to strike substantial portions of Staff's Initial Brief on this topic, specifically three appendices to Staff's brief that presented a complex example that Staff had not presented in its testimony, even though it had ample opportunity to do so, and the related discussion in the text of Staff's brief. (See Illinois Power Company's Motion to Strike Certain Portions of the Initial Brief of the Commission Staff, filed December 20, 2001) The ALJ denied this motion to strike on December 28, 2001. IP notes that in its Response to the Motion to Strike, Staff asserts that the appendices in question "are not evidentiary." (Response to Illinois Power Company's Motion to Strike, p. 1) If that is true, then the examples presented in these appendices and the related discussion in Staff's Initial Brief can provide no basis for the Commission's decision in this matter. On the other hand, if, as IP contends, the appendices and related discussion do constitute "evidence" which was not submitted for, and is not included in, the record of this proceeding, then these portions of Staff's Initial Brief should have been stricken by the ALJ. In either event, IP objects to any consideration or reliance by the Commission on the portions of Staff's Initial Brief that were the subject of IP's Motion to Strike. Reliance on this material by the Commission as part of the basis for its decision relating to the SCR provision would not result in a legally-sustainable order.

[53] Under IP's proposal, the SG customer would be billed three times the applicable demand charge, distribution capacity charge and transformation capacity charge (the latter two, if applicable to the customer) for any demand in a month in excess of 110% of the customer's SCR. (IP Ex. 6.6, p. 21; IP Ex. 6.14, p. 17) Thus, for example, a customer that had designated a SCR of 10 MW, but registered a demand of 12 MW on the IP system in a particular month, would be billed, for that month, three times the demand charge, distribution capacity charge (if applicable to the customer) and transformation charge (if applicable to the customers), times 1 MW.

customer. As IIEC correctly states, "If a customer were to contract for 10 MW of standby generation capacity from a RES, it would make no sense not to contract for a commensurate amount of standby delivery capacity to deliver the power in those events when it is needed." (IIEC Init. Br., p. 21) In other words, the SG customer will know exactly how much standby generation capacity it needs and has contracted for from a RES, and therefore it should be quite capable of accurately specifying its SCR for delivery services. Accordingly, the risk of the customer exceeding its SCR (by more than 10%) and incurring the triple demand charges on that incremental demand should be virtually non-existent – **unless** the customer deliberately understates its SCR to save money, an act of gaming that the triple demand charge provision is intended to discourage, just like the $6 per therm charges to gas transportation customers for taking unauthorized overrun gas that this Commission has approved in the tariffs of Illinois gas distribution companies.[54] (See IP Ex. 6.14, p. 19) For these reasons, the claims that the triple demand charge provision is unnecessarily "punitive" (IIEC Init. Br., p. 23; see also Staff Init. Br., p. 87) must be dismissed – because the only

[54] The customers who would be subject to the SCR provision are among the most sophisticated on the IP system. The SG customers are sufficiently sophisticated about their energy usage and supply to (1) acquire and install an SG facility of sufficient size to serve some or all of their on-premises electricity needs, (2) operate and maintain the SG facility, and secure sufficient electricity supplies from other sources to serve the portion of their on-premises load not served by the SG facility during normal operation, (3) coordinate the operation of the SG facility with any external supply sources used to serve the customer's total load, (4) contract with a RES for sufficient standby electric capacity to meet the non-curtailable load when the SG facility is out of service, or operating at a reduced level, and (5) arrange for delivery service in sufficient capacity to deliver any RES-provided supply, when needed. It is extremely unlikely that such a sophisticated electricity user will incorrectly estimate the amount of standby delivery capacity it needs in order to deliver its RES-supplied electricity, particularly by enough to go outside the 110% window provided under IP's SCR proposal.

truly likely scenario in which it would be triggered is one in which the SG customer has *intentionally* understated its SCR, and gotten caught.[55]

Indeed, the "triple demand charge penalty" may in fact be insufficient to deter gaming. Consider a customer with a 10 MW on-premises load, all of which is normally served by a SG facility, but who specifies only a 5 MW SCR. Assume that for 11 months, the customer's SG facility operates successfully to serve the entire on-site load (or, during periods of reduced operation for the SG facility, the customer is able to curtail its load correspondingly). If in month 12, the SG facility experiences an unscheduled outage and the customer takes 10 MW from a RES – delivered over IP's system – the customer will be billed three times the applicable demand, distribution capacity and transformation charges times 4.5 MW (i.e., 10 MW minus (1.10 X 5MW) = 4.5 MW), or 13.5 demand charge "units" (i.e., 3 X 4.5 = 13.5). However, during the preceding 11 months, although the customer had access to IP's delivery system for his full requirements (10 MW) whenever he might need it, the customer in fact avoided 5 MW of demand, distribution capacity and transformation charges in those 11 months – a total of 55 demand charge "units" (i.e., 5 X 11 = 55). Clearly, intentionally understating its SCR paid off for this customer, even with the triple demand charge "penalty."

IIEC proposes that the SG customer should simply be allowed to contract with IP for the necessary amount of standby delivery capacity. (IIEC Init. Br., p. 24) In essence this is what IP has proposed, but without the need for potentially lengthy contract negotiations (which IIEC witness Stephens testified might ultimately have to be resolved by the

[55] The SG customer's standby electric energy contract with its RES will be a private contract between these parties – IP will not have access to this contract as a means to verify the SG customer's actual standby delivery requirement.

Commission (Tr. 684)), that in any event will create administrative costs for both parties. Simply put, IP will accept the SCR amount designated by the customer (see IP Init. Br., p. 95) – there is no need for contract negotiations. IP's proposal leaves it up to the customer to specify the SCR amount based on its knowledge of the energy that will have to be delivered to its premises to serve its load if its SG facility goes off line, and the amount of its standby capacity contract with a RES. However, one suspects there is another shoe to drop in IIEC's proposal. For example, IIEC never states what happens, under its "negotiate a contract" proposal, if the customer in fact exceeds its contracted SCR amount.[56] (See IIEC Init. Br., p. 24) Does the customer's SCR ratchet to the new, actual demand amount (which is what IP has proposed)? Is any "penalty" or extra charge paid by the customer for exceeding the contract amount – or does the breaching customer simply get a free ride at the expense of IP and its other customers? IIEC studiously avoids addressing these issues in its proposal, and one suspects not due to inadvertence.

Using the long and laborious examples detailed in Appendices B, C and D to its Initial Brief, Staff purports to show that IP's SCR proposal is discriminatory to SG customers as compared to non-SG customers. (Staff Init. Br., pp. 74-79, 83) IIEC makes a similar argument, using an example presented in the testimony of IIEC witness Stephens. (IIEC Init. Br., pp. 22-23) While the mathematical outcomes of these hypothetical scenarios are a function of the assumptions they are based on, they suffer from two fatal flaws that leave

[56] As IIEC (and the Commission) are well aware, the SG's customer use of the delivery system cannot be physically limited to the amount of the customer's contracted SCR capacity. Whatever on-site load cannot be served by the SG customer's SG facility, or curtailed, will be "served" by the IP system, whether intentionally or inadvertently. While the cost to the customer of electricity supplied by IP in excess of what the SG customer gets from its RES in such circumstances is not part of this issue (or of the SCR proposal), the fact that the SG customer will in these circumstances use more delivery capacity than its contracted SCR is.

them not useful to establishing their proponents' contentions. First, they reflect perfect foresight (and hindsight) of what the monthly demands of each customer in the hypotheticals will be. This is unrealistic. Keeping in mind that the objective is to recover an annual revenue requirement through a monthly charge (Tr. 936); if one knew with perfect foresight what demands each customer was going to place on the system in the upcoming year, one could (putting aside the administrative costs involved in the exercise) design a set of charges that fairly and accurately recovered from each customer the costs imposed by that customer's actual use of the system. However, we don't have that foresight, so demand, distribution and transformation charges must be designed based on the information that *is* available. The most critical piece of available information is that *so long as the SG customer remains connected to IP's distribution system, he has the ability to utilize it to deliver his full load requirements, with no notice*, whether he uses this service each month or not. (IP Ex. 6.14, p. 22; Tr. 933-34) Therefore, the customer should pay for this service, which is what IP's SCR proposal accomplishes.[57]

Second, while Staff and IIEC use their examples to criticize the fact that the non-SG customer is not required to specify a SCR, but rather simply gets billed on the basis of its monthly maximum demands (for demand charges) and its maximum demand in the prior 12

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[57] Staff's Initial Brief on the SCR proposal is replete with examples and discussion of SG customers that have SG facilities of differing reliabilities, or that decide to use their SG facilities to peak shave, or not to run them, etc. (See, e.g., Staff Init. Br., pp. 71-73, 78, 82) But the utility has no way of knowing in advance which SG customers have more reliable or less reliable facilities, or how the various SG customers intend to operate their facilities. Nor will IP know this based on historical data, since the appearance of an SG customer's load on the delivery system in a month could be due to an unscheduled outage of the SG facility, an economic shutdown because power is available from a RES at a price cheaper than the cost of operating the SG facility, or an inadvertent failure to curtail load. Moreover, even if the utility has access to performance data for the SG unit, historical performance of an SG unit is not necessary a predictor of future performance.

months (for distribution capacity and transformation charges, if applicable to the customer), the fact is that in most cases the non-SG customer's maximum monthly and annual (prior 12 months) demands are a good indicator of its ongoing, month-to-month level of demand on the IP system. (IP Ex. 6.14, p. 21) This is not the case for the SG customers. Therefore, using actual monthly and annual demands to bill non-SG customers while using SCR to bill SG customers is reasonable and non-discriminatory.

Finally, Staff argues that IP's proposal will discourage the installation of otherwise economic SG facilities on the IP system.[58] (See, e.g., Staff Init. Br., pp. 66-67) Staff's assertions are based solely on the non-quantitative contentions of Staff witness Haas. Staff witness Haas presented no analysis in his testimony of the economics to the customer of the decision to install self-generation, nor of how that decision might be affected by IP's SCR provisions. (Nor was he able to come up with a subsequent example on this point to put in Staff's brief.) However, once again it is the argument presented by IIEC that deflates Staff's assertions. As IIEC points out, the cost of standby generation capacity to the SG customer is likely to be on the order of dollars per kW, while the cost of the standby delivery capacity is likely to range from 2 cents to 40 cents per kW. (IIEC Init. Br., p. 22) In other words, the cost of the standby generation capacity is likely to be several multiples of the cost of the standby delivery capacity. And the cost to the customer of reserving standby generation capacity, of course, is in addition to the customer's investment to install the SG facility and to operate and maintain it (including fuel costs). Further, even under Staff and IIEC's

[58] Staff asserts that encouraging SG will bring various benefits to the system, including "more sources of competitive generation (lower on-peak and off-peak prices)." (Staff Init. Br., p. 66) However, as Staff witness Haas testified, the generation facilities affected by IP's SCR provision are facilities installed on a customer's premises to serve that customer's on-site load, not generation installed for the purpose of selling energy into the system or to third parties. (Tr. 912-13)

proposals, the cost to the SG customer of standby delivery capacity is not zero. In short, it is extremely unlikely that IP's SCR proposal is going to make the difference in the economics of whether to install SG facilities for any customer (IP Ex. 6.14, p. 21), and Staff witness Haas presented no quantitative evidence to show otherwise.

In any event, while Staff hypothesizes about the possibilities for self-generation on the IP system in the future, IP is concerned about the present, namely, about implementing a rate design that properly recovers from the nine SG customers on its distribution system their fair share of the cost of that system. (just as it is concerned about correctly recovering the cost of service from non-SG customers).[59] These nine customers are already connected to the existing distribution system, which has been built to serve their full requirements and is available to deliver their full requirements at any time, on no notice.[60] These SG customers have necessitated the same investment in distribution facilities to serve them as for non-SG customers. IP cannot assume that the SG customer's SG facility will be running at the time of the peak load on the distribution circuit, nor can IP reduce the load-carrying capability of the circuits that serve these customers just because they now have SG facilities. (IP Ex.6.6, p. 25; IP Ex. 6.14, p. 20, Tr. 913-14) Therefore, IP must implement rate design provisions that recover the costs of the distribution system that has been put in place to deliver these customers' requirements to them when needed, and that do not allow them to avoid full cost

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[59] Since there are only nine SG customers on IP's system (IP Ex. 6.6, p. 24) and only two active SG projects in IP's service area (Tr. 915), there has not been a rush to install SG in IP's service area, even without the SCR provisions in effect.

[60] Since each of the nine SG customers is served on a different distribution circuit among IP's almost 800 distribution circuits, the SG customers' presence provides no load diversity benefits to the distribution system that can be recognized in designing rates for them. (IP Ex. 6.6, pp. 24-25)

responsibility simply because their demands on the system are erratic. IP's SCR provisions accomplish this objective, and should be approved.

4. Lighting DST Rate Design

IP's proposed DST rate design for residential and non-residential lighting customers was summarized at pages 99-100 of IP's Initial Brief. The other parties did not raise any concerns or objections with respect to IP's lighting rate design in their initial briefs.

5. Meter Charges for DST Customers

As described at pages 99-100 of IP's Initial Brief, the Company determined metering charges on the same basis as approved in the meter unbundling case, Docket 99-0013. Staff witness Lazare, the guru of embedded costing for unbundled metering, has proposed essentially the same metering charges as the Company. (Staff Ex. 22.0, Sched. 14.4 Rev. and 14.5 Rev.) IIEC has complained about certain aspects of the Company's ECOSS for metering costs (see discussion in §III.A.2.b and c of IP's Initial Brief and § III.A.2.b and c of this Reply Brief), and has proposed that metering charges, facilities charges and demand charges for the demand-metered class all be increased on an equal percentage basis. (IIEC Init. Br., pp. 14-15) Since, as discussed in the section of IP's Initial and Reply Briefs cited above, IIEC's criticisms of IP's meter ECOSS are without merit, its proposal for a non-cost based, across-the-board increase to these charges must also be rejected. The Company's proposed metering charges, which are based on the embedded cost of metering determined in accordance with the criteria determined in Docket 99-0013, should be approved.

IV. IP'S TARIFF TERMS AND CONDITIONS ARE JUST AND REASONABLE AND SHOULD BE APPROVED

A. In General, IP's Efforts at DST Simplification and Reorganization Have Been Successful and Not Contested

As a part of its filing, IP undertook a re-write of its DST and related tariffs for several purposes. (See IP Init. Br., pp. 101-02) With the exception of the issues discussed below in other parts of this Section IV, no party (in Briefs or otherwise) objected to IP's tariff re-write. Based on the lack of objection and in light of the evidence discussed in IP's Initial Brief, IP's tariffs should be approved as originally proposed in this case (or as modified by IP in subsequent testimony in response to criticisms or suggestions by other parties).

B. IP Proposed (and No Party Objected to) Miscellaneous Fees for Various Services

In our Initial Brief, we described the miscellaneous fees IP is proposing and the record evidence supporting each of them. (IP Init. Br., pp. 102-07) The Initial Briefs of every other party in this case are silent on these fees. Thus, based on the lack of objection by any party to any of these fees, the lack of any alternatives proposed by any party and the evidence in the record, IP's off-cycle switching fees, PPO calculator fee, monthly customer usage data fee (as an alternative to the per request fee) and copying fee should be approved. For the same reasons, IP's updated Single Bill Option ("SBO") credits should be approved.

C. IP's Updated Transition Charge Tariff Should Be Adopted

In our Initial Brief, we explained the various changes IP is proposing to its TC tariff to update it for residential delivery services customers and to implement other changes. (IP Init. Br., pp. 107-09) Again, the initial briefs of every other party are silent on this topic. Given the lack of objection to IP's revisions to Rider TC and the evidence in the record on these revisions, they should be approved by the Commission.

D. Revised Rider PPO Should Be Approved

IP has proposed a number of changes to its current PPO tariff, Rider PPO. (See IP Init. Br., pp. 109-13) With the exception of whether a particular factor (Factor A4c) should be included at this time, the initial briefs of the other parties are silent on any of IP's proposed changes. Before responding to the one objection, we note that, based on the lack of objection and the evidence in the record, IP's revised Rider PPO should be approved.

The lone objection to Rider PPO was not based on the substance of IP's proposal, but rather solely on the timing of adding in a particular factor. (IIEC Init. Br., pp. 34-35) As explained in our Initial Brief (pp. 109-11), Factor A4c adds to the delivery service revenue component of the TC calculation an amount to reflect IP's net revenues from energy imbalance service. Because of the equation used for calculating TCs, this addition lowers the TCs paid by a customer. PPO customers (who to be eligible must have a positive TC) are not charged for energy imbalances. Therefore, these customers should not receive a credit, in the form of lower TCs, for delivery services charges they do not pay. To fix this problem, IP proposes adding Factor A4c to the price a PPO customer pays under Rider PPO.

The only party to oppose this change to Rider PPO is IIEC. IIEC does not dispute any of the facts relating to this change, including the fact that initially the change has no effect on customers. (See IIEC Init. Br., pp. 34-35) Rather, IIEC's concern focuses on including this factor at this time. In an effort to create an issue where none exists, IIEC raises a specter that does not in fact exist: the specter of a utility unilaterally setting the price for imbalance service without any oversight. (Id., p. 35) As even IIEC appears to realize (by pointing out that this Commission has intervened at FERC repeatedly, id.), imbalance service is regulated by FERC. As such, IP will not be able to unilaterally set the price for this service. Nor will it be able to unilaterally determine how revenues in excess of cost (if any) are handled. The whole reason IP needed to change Rider TC with respect to Factor A4c was due to a change in its FERC tariff on the very issue of net imbalance revenues. (IP Init. Br., p. 109) And, as even IIEC recognizes elsewhere in its Brief (p. 34), IP must offer its FERC-jurisdictional delivery services at the same prices as set forth in the applicable FERC tariff. (§16-108(a))

IIEC's efforts to focus on the non-existent is little more than an attempt to avoid the real issue here: IIEC does not (and cannot) dispute that under its proposal to omit Factor A4c from Rider PPO, PPO customers will be receiving a credit in the calculation of their TCs for charges they do not pay because no imbalance charges are paid by PPO customers. In fact, this asymmetry can have a negative effect on a RES' ability to serve these customers: the total price of service under PPO (an alternative available to any non-residential customer with a positive TC) is reduced below what it should otherwise be, making it harder for RESs to compete with PPO service for these customers' business.

In sum, given the logical consistency created by including a Factor A4c off-set in Rider PPO, and the paucity of compelling reasons for not making this change at this time, IP's proposal to add Factor A4c to Rider PPO should be approved.

E. IP's Proposed Rider ISS Should Be Approved

As we explained in our initial brief, IP's current pricing for energy provided under ISS, as approved by the Commission in IP's 1999 DST Case, is based on its Real Time Pricing ("RTP") rate. (1999 DST Order, pp. 123-24) The purpose behind this pricing mechanism is that "default service *should be temporary in nature and that it must not be a vehicle for rate arbitrage*. (Id., p. 124 (emphasis added)) More recently, the Commission has rejected ISS pricing that "would provide opportunities and incentives for RES's and residential customers to game the system . . . " (Docket 00-0802, Order, p. 50)

1. <u>IP's Pricing for ISS for Residential Customers No Longer Appears to Be an Issue</u>

In setting the ISS price for residential customers, IP chose to use the same pricing mechanism that it uses for non-residential customers. (IP Init. Br., pp. 114-17) In testimony, only one party (Staff) argued for different pricing for residential customers served on ISS. However, in its Initial Brief, Staff makes no mention of its alternative proposal for pricing residential ISS service.[61] In light of the apparent abandonment of this issue (as well as the record evidence cited in our Initial Brief), IP's proposal should be adopted.

2. <u>IIEC's Concerns With ISS Pricing Should Be Rejected</u>

In contrast to Staff, IIEC continues to take issue with the way the base cost of energy is adjusted and the way transmission service is priced for ISS customers. (IIEC Init. Br., pp. 25-30) Turning to the latter point first, the short answer remains that, despite numerous rounds of evidence, hearings and an initial brief, IIEC continues to refuse to present any cogent argument on transmission pricing for ISS customers. Although IP pointed these problems out in rebuttal testimony and in its Initial Brief (p. 119), IIEC provides no counter to any of them. IIEC's only statement on this issue in its Initial Brief is that it "disagrees" with IP. Given IIEC's repeated inability to explain its position on transmission pricing, the Commission should decide that IIEC has dropped this issue. In any event, IP's recitation of the record evidence (IP Init. Br., p. 119) shows why IIEC's position should be rejected.

[61] IIEC's Brief (p. 30) contains a factual error when it asserts that "[f]or a non-residential customer on Rider ISS, the customer currently pays the Rider PPO market price. . ." Given its lengthy disagreement with IP's actual pricing for non-residential ISS service, (IIEC Init. Br., pp. 25-30) IIEC must be aware that ISS is, in fact, based on DA-RTP pricing. In any event, this is of no consequence with respect to residential ISS since IIEC does not object to the Company's proposal to make residential and non-residential ISS pricing be on the same basis. Nonetheless, IIEC's error highlights the erros that are the hallmark of its arguments on IP's ISS pricing structure more generally (to which we turn in our next subsection).

With respect to the adjustments to the base energy component, IIEC begins from a false premise and proceeds to misstate other parts of the record in an effort to change a pricing provision previously adopted by this Commission. The false premise is "*if* Rider DA-RTP is recovering the market energy price at the time the customer is taking Rider ISS, *as IP contends* . . . ." (IIEC Init. Br., p. 25 (emphasis added)) Not only is the "if" clause wrong, but we never contended otherwise (and the IIEC provides no record citation to the contrary). As we pointed in our Initial Brief (pp. 117-18), DA-RTP is a bundled service that applies to a customer's *incremental* load with rates set to be collected over a period of at least one year. Thus, using DA-RTP pricing is intended to recover the market energy price *over the period the customer is taking Rider DA-RTP*. In contrast, ISS is an unbundled service whereby the utility may be required to serve a customer's entire load on no notice for a very short period when energy prices may be extraordinarily high. Thus, there is no reason to believe that DA-RTP would recover the *ISS* market energy price *over the period the customer is taking Rider ISS*. And, IP's witness clearly rejected looking only at one component of this service to set the price: "the total price of the service represents the market price of the service." (Tr. 426) Thus, IIEC is wrong when it contends that (1) the energy component of DA-RTP pricing recovers the market price for ISS service; and (2) IP ever acceded to IIEC's incorrect assertion.

Unfortunately, by starting down this false path, IIEC continues to uncover other incorrect "facts" and ends up at the wrong conclusion. *First*, IIEC attempts to transform ISS from what it is into a strictly cost-based service. (IIEC Init. Br., pp. 25-26) ISS is priced using a market-based methodology, not a strictly cost-based one. Also, ISS is intended as a default service that is priced to minimize gaming opportunities, in accord with this Commission's views on this service.

Second, IIEC incorrectly changes the fact that Mr. Peters (one of IP's witnesses) was not aware of any alternative suppliers offering a service similar to ISS into an admission that no suppliers, in fact, are doing so. (IIEC Init. Br., p. 26) The transcript page cited by IIEC (Tr. 454) contains no discussion of alternative suppliers, much less the "admission" purportedly found by IIEC. Rather (as IIEC cites earlier on the same page of its own Initial Brief), Mr. Peters is merely unaware of any such suppliers. But, as with so many of IIEC's other distortions of the record, this one is ultimately focused on the wrong issue. Under IIEC's proposal, customers and RESs who realize that they can obtain power and energy at a price below the market price of the service they are receiving will have every incentive to take advantage of this service. (IP Init. Br., p. 118) The evidence in the record bolsters this point: as currently priced (i.e., not at the lower prices urged by IIEC), RESs and their customers have chosen to use ISS as bridge pricing even though they had options available to avoid taking ISS service. (IP Ex. 11.1, p. 13) And, the record is devoid of any evidence of customers or RESs complaining that the ISS price is too high. Under IIEC's proposal, RESs and their customers would receive even lower pricing, providing RESs with no incentive to develop alternative ISS services. Rather, RESs would have perverse incentives to use ISS for their customers. This is bad policy and has been rejected by this Commission as such.

Third, IIEC disputes whether a RES or a customer could have an incentive to act quickly, based on a statement by Mr. Peters on cross-examination relating to billing. (IIEC Init. Br., pp. 25-26) First, as even Mr. Peters stated in his testimony, he does "not handle billing." (Tr. 446) In any event, it is IIEC (and not IP) that does not understand how a RES or customer could know the unit price for ISS the day before the customer uses the energy at issue. The "DA" in DA-RTP stands for "Day Ahead" and, as Mr. Peters explained, IP sets the price for tomorrow based on its look at today's situation. (Id.) While the customer's usage may not be known until after the fact (and, indeed, may need to be split according to profiles), the *per unit* price can be known the day before the event and thus can serve as a very real incentive to find an alternative service.

Fourth, IIEC draws the wrong conclusion from the evidence of those few customers who have ended up on ISS. This evidence does not prove that ISS is not being abused as IIEC contends. (IIEC Init. Br., p. 27) The evidence is that not a single customer has been on ISS due to the default of its RES. Thus, every customer was placed on ISS under circumstances where ISS could have been avoided. And, every such customer and/or their RES would have the necessary information available to decide whether ISS pricing beat the next available alternative. The fact that 24 customers and/or their RESs have chosen ISS is strong evidence that, even as currently priced, ISS is not priced high enough to be a complete antidote for all abuse. There is certainly no reason to price it lower.

Fifth, IIEC subtly transforms the numerous steps a customer "may" take into "what a customer must do" to take service from a RES. (IIEC Init. Br., p. 27) IIEC has not actually pointed out the very few steps a customer must actually take to move to third party supply (most of which, in fact, are (or can be) done by the RES). Rather, it parades a laundry list of things a customer may choose to do. We agree that all of these may be actions a customer might choose to take, but not all of these "must" be done. More importantly, there is no reason that a customer needs to wait until it is on ISS to do any of these things. By their very nature, long-term supply arrangements provide sufficient time for customers to plan their next steps *before* they find themselves on default service.

Apparently recognizing the weakness of its point, IIEC continues by distorting the record. IIEC contends that a customer on ISS "has to be there for a minimum of 10 days." (IIEC Init. Br., p. 27, citing Tr. 442) In fact, that portion of the transcript relates to a hypothetical with very specific assumptions. (Tr. 441-42) Under the constraints built into the hypothetical, the minimum stay on ISS is 10 days, but under different circumstances, the minimum stay can be much less—as little as one day.[62]

IIEC goes on to distort the record as to the experience of Mr. Peters by claiming he "has not worked with retail customers in his employment." (IIEC Init. Br., p. 27) In fact, what Mr. Peters said is that he has not worked *on behalf* of retail customers. (Tr. 430-31) Rather, as he pointed out, his group assisted in "making offers *to those groups* . . ." (Id. at 431 (emphasis added)) Furthermore, in his rebuttal testimony, Mr. Peters described his experience in analyzing retail contract proposals and determining ways to meet current and potential customer needs. (IP Ex. 11.1, p. 2) Thus, Mr. Peters has the very experience IIEC thinks is important in qualifying a witness on this topic, but from the opposite vantage point of its customers.

Sixth, IIEC's next distortion is its attempt to transform ISS service into a bundled service: "IP has had the benefit of a power purchase agreement to serve its bundled load, which includes Rider ISS load." (IIEC Init. Br., p. 28) ISS is only available to delivery customers and is clearly not bundled service. IIEC's distortion masks the important issue

[62] This can be seen from the following hypothetical: Customer is served by RES A for the period through Day 1. RES B, Customer's new supplier, timely submits a DASR to serve Customer effective Day 3. Under these circumstances, Customer is on ISS 1 day (Day 2).

here: ISS is not meant to be similar to bundled services, which are designed to be cost-based. As we described above, the intent behind ISS is to offer a market-based, default service that minimizes gaming opportunities.

Finally, IIEC essentially ends where it began by comparing ISS to various bundled services and complaining of the differences in pricing approved by the Commission in each of those instances. (IIEC Init. Br., pp. 28-30) Had IIEC begun down the proper path, it would never have ended up attempting this improper comparison. Bundled rates (whether DA-RTP or DA-RTP II or any other tariff) and the various components of them cannot be used to justify lowering a market-based, default service rate that has been priced to minimize the incentives of other market players to game the system. And, the market rate is the entire price charged, not just one component of that price.

In sum, IIEC's proposed changes to the pricing of ISS service should be rejected as contrary to the record evidence and to the Commission's goals relating to this service.

3. To Prevent Gaming, Customers Moving From a RES to ISS Should Not Be Allowed to Return to that RES for One Year

As noted above, one of the fundamental points recognized by this Commission is that RESs should not be allowed to use ISS as a gaming opportunity. One of the provisions in IP's ISS tariff directly prevents RESs from using ISS as a gaming opportunity. Specifically, a customer who is served by a RES and then ends up on ISS cannot return to service from that RES for 12 months. This prevents the RES from using ISS as a supply option for certain periods but then resuming service to the customer when prices change favorably.

Nonetheless, both Staff and MEC continue to oppose this limitation. (Staff Init. Br., p. 91; MEC Init. Br., pp. 2-4) In our Initial Brief, we addressed Staff's alternative proposal (i.e., to use hortatory language in the tariff). (IP Init. Br., p. 121) In its Initial Brief, Staff now focuses on a "do nothing" approach. (Staff Init. Br., p. 91). Under this approach, the parties would collectively stick their heads in the ground and ignore the facts of how ISS has been used to date.[63] Instead, we are asked to remove the last roadblock to gaming and await the inevitable. Staff does not explain what cure it would then propose. Nor does Staff opine on how quickly the cure could be implemented assuming new tariff language were put in place. Because IP already has in place language that effectively minimizes the very gaming this Commission is concerned about, there is no reason to remove that language to see if RESs (and their customers) are smart enough to realize they can then game the system.

Like IIEC, MEC starts from a faulty premise and continues with an example and a number of rhetorical questions that underscore the points IP has tried to make on this issue. (MEC Init. Br., pp. 2-4) Like IIEC, MEC appears to have taken the 10-day minimum in one constrained hypothetical and expanded it to be the minimum stay on ISS under any circumstance. (Id., pp. 2-3) As we explained above, this simply is not true.

MEC continues with an example of a residential customer who inadvertently forgets his electric contract's expiration date. (MEC Init. Br., p. 3) As with MEC's prior examples (which we dispatched in our Initial Br., pp. 121-22), this one actually underscores our point: MEC nowhere discusses what the RES is doing *or should have done*. To follow MEC's rhetorical style, is the RES that uninterested in serving this customer that it took no steps (such as letters or calls) to inform the customer of the impending expiration? Why didn't the RES build in a bridge in the original contract to handle such events? Are people that

[63] These facts demonstrate that no customer to date has been on ISS due to a RES' default. Given that ISS customers currently cannot return to their prior RES, this evidence alone suggests that even more gaming would occur if successive switching were permitted.

unconcerned about termination of service that they will ignore expiration letters for electric service but answer those for renewal of a magazine?

Furthermore, there is nothing "unduly harsh" about IP's no gaming provision. (MEC Init. Br., p. 4) Actions (and inactions) have consequences—good, bad or unintended. Does anyone reasonably anticipate no consequences from driving on an expired license? In any event, MEC never explains why it is IP that should suffer the consequences of the RES' and customer's inactions.

In light of the problems with Staff's proposal and the evidence that gaming can occur without a limitation such as contained in IP's Rider ISS, IP's tariff language (limiting return to the prior RES for 12 months) should be adopted, and Staff's and MEC's positions rejected.

F. IP's Provisions Pertaining to Return to Bundled Service from SC 110 Should Be Adopted

1. Customers Should Not Be Able to Rescind Notice of Return to Bundled Service Within the 30-day Notice Period

Both Staff and IP are in agreement: resolution of this issue would be better handled in a workshop process. (Staff Init. Br., p. 104) Although the IIEC purports to address this issue (IIEC Init. Br., p. 35) along with several others, its brief addresses other issues and not the rescission period once a customer chooses to return to bundled service. Under these circumstances and as an interim measure until workshops can be held and a resolution reached, IP's proposed language should be adopted, especially since no mechanism currently exists for IP to recover its legitimate costs if different language were used.

2. The PUA Permits IP to Require Residential and Small Commercial Customers to Remain on Bundled Service for 24 Months After Returning from Delivery Service

Staff recommends that IP accept a shorter return period for small commercial and residential customers who return to bundled service. (Staff Init. Br., p. 104) Staff does not disagree that the law entitles IP to set the return period for residential and small commercial customers at 24 months. As we stated in our Initial Brief, IP is not willing to use a shorter period at this time. (IP Init. Br., p. 124) Accordingly, IP's provision requiring a residential or small commercial customer who returns to bundled service from delivery services to remain on bundled service for 24 months must be approved.

G. IIEC's Arguments Relating to the Departure from, and Return to, Bundled Service Should Be Rejected

IIEC has raised three issues relating to the operation of IP's *bundled* tariffs. (IIEC Init. Br., pp. 35-40) As we pointed out in our initial brief (pp. 124-28), there are numerous specific reasons to reject each of IIEC's positions. But equally important, there are other reasons that go to the heart of all of IIEC's positions. Of the two we raised in our Initial Brief, only one bears mention here (the IIEC offered no argument on the other). Not a single bundled tariff that IIEC would like to see modified was filed by IP for modification in this proceeding, as even IIEC does not dispute. Rather, IIEC claims (IIEC Init. Br., p. 38) that IP agreed to make changes to its bundled rates in its last DST case and therefore, we should be willing to do so now. IIEC is missing the point: we have not proposed doing so in this case and are not willing to do so now. Rather, it is IIEC that seeks to expand the scope of this case beyond what it rightfully should be: a delivery services tariff case.[64] That alone should suffice to reject each of IIEC's contentions.

IIEC also attempts to cast aspersions at IP for the pace of competition in its territory. (See, e.g., IIEC Init. Br., pp. 36-37). However, as even IIEC admits, there are a variety of reasons for the current state of affairs. (Id., p. 36). Although many of these reasons are beyond IP's or this Commission's control, IIEC misses the whole point: making bundled service even more attractive (e.g., by re-opening closed tariffs) will do little to encourage customers to seek choice. Rather, this unwarranted attractiveness will make customers more likely to choose bundled rates—the very outcome IIEC purports to be against.

In addressing its specific proposals, IIEC blends various items of its three proposals with incomplete versions of IP's rejoinders to create an unsatisfying hash. To restore these issues to their original form, we sort through them individually to reveal their true flavor.

1. IP's Current Provision in SC 24 on the Notice Required to Terminate an SC 24 Contract Should Not Be Modified

Under IP's bundled SC 24, a customer who wishes to terminate service under that tariff must provide 12 months notice to do so (assuming it has already fulfilled its primary term obligation under SC 24). Well before the advent of the current case, IP adopted a policy that permitted a customer to rescind this notice (and thereby remain on SC 24 for another 12-month period) up to 60 days before the termination date. (IP Init. Br., p. 125)

[64] Equally disingenuous is IIEC's attempt to claim that it merely seeks to change IP's DSTs. (IIEC Init. Br., p. 34) Every provision it seeks to change is (and has been long before there were DSTs) contained in IP's bundled tariffs. IIEC's semantics only serve to underscore the discriminatory nature of its proposals: it seeks to change the rules now to serve a few customers, to the detriment of all those who made choices under IP's longstanding policies.

As currently constituted, IIEC would like IP to grant all SC 24 customers who are outside their primary term the right to leave SC 24 on 30 days notice. (IIEC Init. Br., p. 36)[65] Having provided a comprehensive rejoinder to IIEC's arguments in our initial brief, we respond to only a few new points raised by IIEC. IIEC is concerned that 60 days is not enough time for customers to act because of all the steps they "must" take when deciding on supply alternatives to ISS (IIEC Init. Br., p. 27), yet these same customers now need only 30 days when they want to leave bundled service. IIEC cannot have it both ways.

More importantly, IIEC fails to grasp, much less offer any rejoinder to, the fact that changing SC 24 has a disparate impact on various large customers. (IP Init. Br., pp. 125-26) As if to underscore its lack of understanding on the importance of looking at SC 21 and SC 24 in combination, IIEC fails to even mention SC 21 until the final paragraph of its argument (and then only to address a side issue of which tariff is optional and which is the default). (IIEC Init. Br., p. 40) Simply stated, IIEC is attempting to eliminate one of the *obligations* of SC 24 while retaining its advantageous characteristics for customers compared to SC 21. This mixing of IP's bundled tariffs should not be allowed, particularly in the context of a *delivery services* case. IIEC's proposal must be rejected.

2. A Customer Should Not Be Able to Return to SC 24 Without Complying with the Primary Term Requirements of the Filed Tariff

Along the same lines as its attempt to permit SC 24 customers who have satisfied their primary term obligations to leave this bundled tariff more quickly than its terms allow, IIEC also wants these customers exempted from the primary term requirement of SC 24 if

[65] IIEC also appears to misunderstand its own testimony. With respect to being able to return to closed tariffs (a separate issue), IIEC limits the applicability of its proposal until such time as those rates are declared competitive. (IIEC Ex. 1, pp. 14-15) However, IIEC now mixes that limitation into its proposal on terminating service under SC 24. (IIEC Init. Br., p. 36)

they *return* to SC 24 from delivery services. (IIEC Init. Br., p. 37) IIEC justifies its proposal with an extreme hypothetical. (Id., pp. 37-38) Even assuming, however, the hypothetical as posited, IIEC fails to explain why this outcome is improper *vis-à-vis* a similarly situated SC 21 customer, who paid more for the added flexibility to alter its choice more quickly. More importantly, IIEC fails to recognize that the customer could just as easily have returned from delivery services for one year (on SC 21) and then been free to try the competitive market again rather quickly -- without any discriminatory impact on a similarly-situated SC 21 customer. Fundamental fairness requires that IIEC's position be rejected.

3. Customers Who Choose Delivery Services Should Not Be Able to Return to Bundled Tariffs That Are Closed

IIEC's final ingredient in its hash is to reopen IP's closed interruptible tariffs, at least for those customers who are on them currently and subsequently choose to leave them to go on delivery services and would then like to return to the closed rate. (IIEC Init. Br., p. 36) Here, the IIEC does little more than reiterate its proposal -- refusing to even engage in a debate on the problematic aspects of that proposal. Based on the arguments presented in our Initial Brief (pp. 127-28) and as with IIEC's other proposals, it simply is not fair to those customers who made choices based on a certain set of rules that IIEC now does not wish to follow. IIEC's proposal to reopen closed bundled tariffs that are not even at issue in this case should be rejected.

H. A Retail Delivery Services Customer Remains Responsible for OATT Charges Not Paid by the Customer's TSA or RES

IP's proposed DSTs include language that makes it clear that a retail customer remains ultimately liable for transmission charges if its RES or Transmission Service Agent ("TSA") fails to pay those charges. However, IP's tariff language also makes it clear that

"Before billing the charges to Customer, Utility shall first pursue all reasonable collection actions against Customer's RES . . . or TSA, including initiating a claim against any bond or other security the RES . . . or TSA has posted." (IP Init. Br., pp. 128-31)

Both Staff and IIEC disagree with IP's language on this issue. Staff paradoxically quotes the proper definitions from IP's OATT (Staff Init. Br., pp. 94-95) but then chooses to ignore their import. For example, as even Staff's witness admits, the "eligible customer" for transmission service under the OATT is the retail customer. (See, e.g., Tr. 473-74) Furthermore, as Staff notes, the Transmission Customer is "[a]ny Eligible Customer (or its Designated Agent)". (Staff Init. Br., p. 94, n. 14) The logical conclusion is that, when a RES (which, by definition, is not the retail customer under the PUA) obtains transmission service for the retail customer, it is doing so as the retail/eligible customer's designated agent.

Rather than disagree with this logical conclusion directly, Staff continues by engaging in an exercise of agency law. (Staff Init. Br., pp. 95-99) IP does not disagree with the basic underlying legal principles. Staff, however, focuses on the wrong facts. Everything it says about the complexity of transmission service, the inability of an ordinary customer to competently direct a RES' actions, and so forth, are equally true of numerous other situations in which there can be no doubt an agency relationship exists. For example, attorneys are merely the agents of their clients and yet the average individual engages an attorney precisely because he or she cannot handle the complexities of the law. As another example, many corporations do not attempt to control the specific actions of outside income tax specialists or intellectual property experts. Rather, they describe their situations and the desired outcome and leave the rest to the experts. Yet, there is no doubt these experts are merely agents for the corporations. By retaining a RES to serve them at retail, the retail customer creates the agency relationship just as a person who engages a lawyer for the sale of a house does.[66]

Finally, Staff's contrived and forced "hypothetical" regarding "End-Run" is either irrelevant at worst, or helpful to IP's position at best. (Staff Init. Br., pp. 99-100) Taken as presented, it is irrelevant because it does not actually address the situation at hand -- a customer who requires the assistance of experts to make a transaction occur. As such, it does not address, or purport to be concerned with, two parties attempting to limit a liability to a third party without the third party's agreement. Rather, it addresses negotiations between two principals as to the consequences of possible future events and how the risk of those events will be borne. Viewed this way, Staff's hypothetical is irrelevant.

If, however, somehow one could read this example as being apposite, then it is helpful to IP's position. As between the two parties in the hypothetical, IP believes that those parties are free to negotiate. But, so is any other party. This does not mean that those negotiations affect the rights of third parties. Thus, for example, a retail customer and a RES can enter into any agreement they want with regard to who will pay IP in the first instance for transmission charges. However, without IP's permission, those same parties have no right to waive IP's right to seek payment from the acknowledged retail/eligible customer.[67]

For these reasons (and those in IP's Initial Brief), IP's proposed tariff language is appropriate and should be approved.

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[66] Staff's detour into the workings of Customer Self Managers only underscores this point: some corporations (e.g., those with legal staffs) are sophisticated enough to handle certain specialized needs. (Staff Init. Br., pp. 97-98) But, that exception only proves the rule that outside lawyers act as agents.

[67] This example also demonstrates why IIEC's arguments on this point must be rejected. (IIEC Init. Br., pp. 31-34) Furthermore, as we explained in our Initial Brief (pp. 128-30), §16-108(a) bolsters IP's position, not IIEC's.

I. **The Parties Have Reached a Reasonable Conclusion Regarding An Agreement for "Billing Agents" Relating to Collection and Remittance of IFC Charges**

The only Initial Brief to address this issue was Staff's (pp. 100-01), which did so essentially in the same manner as IP's (p. 131). In light of this, the Commission should approve IP's revised language to Section 6(u) of its Standard Terms & Conditions (set forth in IP Ex. 3.17, p. 18) and the use of MidAmerican Cross Exhibit 1 as a generic agreement that fulfills IP's (and a third party collector's) obligations under Section 6(u).

J. **The Parties Agree that the Issue of Permitting Electronic Signatures for Customer-RES Letters of Agency Is Better Resolved in a Separate Forum**

Staff also addresses the issue of the use of electronic signatures (as compared to "wet" signatures) by customers "signing" an LOA and agrees that workshops are the proper forum for handling the numerous unresolved details. (Staff Init. Br., pp. 101-02) IP concurs that workshops are appropriate and points out that the complexity of the issues is underscored by the lengthy legal discussion provided by CUB/AG. (CUB/AG Init. Br., pp. 31-35)

K. **The Commission Should Not Require IP to Split Electric and Gas Bills and Accounts At This Time**

MEC continues to propose that IP split the bills and accounts of combination gas and electric customers. (MEC Init. Br., pp. 4-6) Leaving aside issues that are not directly at issue in this case,[68] IP is willing to accept MEC's suggestion that this issue be handled in further discussions (with the upcoming uniformity workshops being an appropriate forum). This goes beyond even Staff's modified position of monitoring the situation because of the

[68] For example, MEC raises the issue of how SBO billings are applied. (MEC Init. Br., pp. 5-6). IP believes that its current process fully complies with the Commission's Order in Docket 00-0494. The confusion arises because of the way certain terms are used and systems are programmed to work around other billing needs while nonetheless ensuring compliance. IP would be willing to discuss this point with Staff, MEC or any other interested party. In any event, IP's SBO process is not an issue in this case.

financial and administrative costs associated with splitting bills. (Staff Init. Br., p.103) Alternatively, IP would be willing to accept Staff's modified position. In no event, however, are we willing to accept MEC's original request, which, as was demonstrated in IP's Initial Brief (pp. 132-33), should not be adopted given the record in this case.

L. **Rider PRS is not an Issue in this Case and IIEC's Attempts to Make it One Should be Rejected**

Finally, IIEC raises an issue that every other party appears to believe is no longer alive in this case: IP's withdrawn Partial Requirements Service ("PRS") changes. (IIEC Init. Br., pp. 40-41) Originally, IP proposed substantive changes to its PRS service (in addition to moving it to a Rider, Rider PRS). However, in light of the problems raised by IIEC and the gaming opportunities raised by IIEC's alternative proposals, IP withdrew its proposed changes. (IP Ex. 6.6, p. 27; IP Ex. 6.14, p. 26)

IIEC's efforts to resurrect this issue should be rejected. IP's current (and only) proposal is to continue with the service that was approved by this Commission in IP's last DST case. In particular, the Commission found IP's PRS meets the requirements of the Act. (1999 DST Order, p. 125) That should end the debate.

IIEC, however, claims that continuing with the *status quo* would be discriminatory since current full requirements bundled customers have an RTP option available to them. (IIEC Init. Br., p. 41) IIEC fails to tell the whole story. In particular, IIEC neglects to point out that full-requirements bundled customers can only take DA-RTP for incremental load above their baseline usage. Furthermore, there is no reason that alternative suppliers cannot (and indeed no evidence that they do not already) offer RTP pricing for delivery services customers such as those represented by the IIEC. There is thus nothing discriminatory in treating differently-situated customers differently.

In light of record evidence and the Commission's prior Order on this topic, PRS should be continued on the same terms as currently provided in IP's DST.

V. **CONCLUSION**

For the reasons set forth in Illinois Power's Initial Brief and in this Reply Brief, the Commission should approve the electric distribution revenue requirement, revenue allocation and rate design for the delivery services tariffs, and the other terms and conditions of delivery services, proposed by Illinois Power in this case.

Respectfully submitted.

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