BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Continue Implementation and Administration of California Renewables Portfolio Standard Program.	)))))	Rulemaking 08-08-009 (Filed August 21, 2008)

FIT COALITION COMMENTS ON ADMINISTRATIVE LAW JUDGE'S RULING REGARDING PRICING APPROACHES AND STRUCTURES FOR A FEED-IN TARIFF

I. INTRODUCTION

The FIT Coalition is a volunteer group of citizens who are passionate about renewable energy and it's critical role in California's low-carbon future. This passion has driven us to seek out the best public policy mechanisms in the world for scaling up deployment of renewable energy. The clear winner has proven to be the Feed-In-Tariff (FIT) as implemented with tremendous success in Germany and a multitude of other places, including Gainesville, Florida.

Based on extensive research, the FIT Coalition has concluded that the cost-based FIT approach, as used in Germany and every other successful FIT program, is the most effective method to meet the goals stated in this rulemaking proceeding. Our expertise in this policy arena is reflected in these comments. In addition to the pricing mechanism, we have included several other design elements that experience has shown to be critical to the success of FIT programs.

Readers of these comments should know that the FIT Coalition is strongly in favor of the Commission's efforts to encourage development and growth of the Wholesale Distributed Generation (WDG) market segment through a FIT mechanism. We commend the Commission for recognizing the importance of unleashing WDG as an essential step in California's pursuit of achieving its Renewables Portfolio Standard (RPS) mandates on schedule.

Our goal is to maximize the impact and success of the Commission's initiative with these comments. You will see that our comments follow two general themes. One theme discusses ways in which we believe the Commission's proposed Renewables Auction Mechanism (RAM) Pricing and FIT Structure could be enhanced. The other theme follows what we have found to be optimal FIT design based on our global analysis of FIT performance. We are confident that our comments will prove constructive for achieving the best possible outcome for the State of California within this Rulemaking.

While it may not be possible at this time to apply a straightforward FIT program to projects larger than 20 MW, it is clear that projects less than 10 MW should utilize processes that are pre-defined, transparent, and predictable so that these smaller projects can be implemented quickly and cost-effectively. This will require the elimination and preemption of market barriers such that there is a level playing field for all participants willing to invest in deploying renewables in California.

II.
DISCUSSION

A. FIT Pricing Approach

The FIT Coalition strongly supports the well proven cost-based pricing approach. For small projects there is no need to introduce a complicated mechanism like RAM that will introduce significant market barriers for new and/or small developers; which would result in an uneven playing field. In case the Commission insists on introducing the RAM, the FIT Coalition make several recommendations that will help minimize the market barriers that this would create. Note that while this document attempts to neatly separate cost and structure for the sake of discussion, it is important to recognize that pricing, structure, processes, and overall FIT design are all interrelated and must be considered as a whole in order to design an optimal FIT program.

B. Energy Division Pricing Proposal (Attachment A)

Responses to the questions set forth in Attachment A regarding the Energy Division FIT pricing proposal are set forth below.

1. Do you agree with the program's goals and guiding principles (see Attachment C for a list of the Guiding Principles)? If you do not agree, please explain.

The FIT Coalition believes that a cost-based approach is the most simple, fair, and effective approach. Hence, we disagree with the use of an unproven, market-based pricing mechanism like the one described in Attachment A, that would introduce market barriers and create an unlevel playing field. With respect to the program goals as set out in Attachment C, we agree with most and disagree with few; some highlights follow:

1. The stated objective of the RAM market-based pricing mechanism: "The key aspect of the mechanism is that the policy provides a long-term investment signal."[1] The WDG market segment is virtually underdeveloped and a long-term investment signal that establishes price certainty for investment is necessary in order to unleash the unparalleled potential of WDG. Since the RAM provides no price certainty whatsoever, the FIT Coalition believes that the RAM is not a viable approach.

2. Goal number 1: "open to all RPS-eligible technologies". The FIT program should not only allow all technologies to participate, but also be structured to account for differences in technology maturity and promote the development of promising new technologies. California will not achieve resource diversity and optimal energy production if promising innovations are forced to compete head-to-head with established older technologies.

3. Goal number 2: "stimulate untapped market segments at the distribution level and build new projects while minimizing ratepayer costs and preserving competition.[2] The FIT program should clearly prioritize the elements of this goal in the correct order. It is critical that the design successfully stimulates the building of significant volumes of new projects. This should be considered simultaneously with minimizing ratepayer costs.

Experience from previous programs has shown that a priority placed solely on minimizing ratepayer impact has caused such designs to fail in the real objective of stimulating renewables development.

4. Goal number 3: "focus on projects of certain size…mitigate…constraints" The FIT program should not only focus on project sizes that can themselves mitigate the constraints, but explicitly address those constraints so that parasitic costs are removed and a wider range of project sizes can participate. We offer specific recommendations to ensure a wide range of project sizes at pre-identified locations will have opportunities to participate in a predictable and cost-effective manner.

5. Goal number 7: "project viability" While project viability criteria could be useful if the anticipated program was deploying multi-GWs per year, the project viability constraints on a tiny 1 GW over 4 years is unnecessary. As currently designed, the project viability criteria are so restrictive that they prevent promising new entrants into the market. Markets can only be competitive and sustainable if new participants can enter bringing innovative practices and products, thereby forcing the existing larger players to continue to innovate and compete aggressively. This competitive mechanism is imperative for maximizing long-term ratepayer benefits from lowest costs, new technologies, and best business practices.

6. Goal number 11: "just and reasonable rates" This goal should explicitly acknowledge the value of renewable energy in terms of GHG emissions reduction, California-based economic stimulation, and long-term sustainability of the economy. In the past, "just and reasonable" calculations have only considered short-term financial impacts. Society is increasingly willing to invest in renewables to mitigate climate change and lessen dependencies on fossil fuels and the external markets that supply fossil fuels.

2. Please comment on the strengths and weaknesses of staff's proposed market-based pricing mechanism, including auction design details, using the guiding principles.

STRENGTHS:

1. The reverse auction mechanism theoretically assures that the price paid for the electricity is the lowest possible while still being high enough to provide sufficient profit to the biggest developers. This mechanism works under the following conditions:
    a. Markets are competitive and have reached economies of scale.
    b. Prices of winning bids are public so that clear price signals are sent to the markets for manufacturing, investment, electricity, installation, etc.
    c. Bids are limited to projects of comparable size, technology, and location.

2. The RAM proposal would shift the responsibility for setting prices and overall program results onto auction participants. This may address some of the questions raised about the Commission's authority to set prices.

3. By setting the price based on bids from developers, the program avoids the pitfalls in the AB1969 FIT program where the price was set too low to stimulate the market. However, to stimulate the entire range of the WDG market segment, bids would need to be separated and ranked according to comparable project size and location.

WEAKNESSES:

1. The proposal states that "The key aspect of this mechanism is that the policy provides a long-term investment signal."[3] The proposal also states that "The price of each individual bid will be confidential…"[4] These statements are mutually exclusive and should be recognized as such for the purposes of the program design. If the price of the winning bid for each project is not public information then the "**key aspect**" of the RAM pricing mechanism will not be fulfilled, and the benefits of providing a long-term investment signal will surely not be realized. More price signal transparency is definitely needed to stimulate investment in manufacturing and development either by revealing the price of the winning bids (as is common practice in many auctions) or by implementing a fixed price mechanism as has been done with successful FIT programs worldwide.

2. The proposed structure clearly favors the largest projects, large existing developers, and regions in the south with the best solar resource. This will inhibit the ability of the market to grow through participation of new and small players. Effectively excluding small and new players in this manner runs counter to several of the program's stated goals:
   A. "Stimulating untapped market segments." The smaller project size market segments will be at a bidding disadvantage and the transaction costs of the auction process may be a barrier.
   B. "Minimizing ratepayer costs and preserving competition." Concentrating activity within only the existing large players will inhibit the realization of economies of scale, decreasing competition and potentially failing to minimize ratepayer costs.
   C. "Regulatory certainty to create a sustainable and long-term market for small developers." Favoring larger projects adds uncertainty and risk for smaller projects. As the market becomes dominated by larger entities, the market for smaller entities cannot be sustained.
   D. "Ensuring economic efficiency." Favoring the largest players will preclude new small businesses from entering the market, becoming established, creating new jobs, and increasing competition. Consequently, the proposed pricing mechanism will fail to develop the majority of the distributed market potential and will fail to maximize competition. Together, these effects will ensure economic inefficiency for ratepayers and all stakeholders.
   E. "Ensuring non-discriminatory access to the electricity market." The proposed mechanism essentially discriminates against smaller participants and small and medium sized projects by favoring larger projects and establishing potentially high barriers in terms of project viability criteria.

3. Critically, **the RAM pricing proposal will not unfreeze capital markets and project financing** because the terms of each deal would be unique, confidential to everyone except the winning bidders, and terms of future deals would be uncertain. **RAM will simply not create enough certainty to meet investors' and lenders' requirements.** It will fail to break the project financing logjam which is one of the primary roadblocks to meaningful market development at this time.
    a. Experience has shown that a high degree of certainty is required for project financing to become generally available. The degree of certainty that has been provided by cost-based FIT pricing has unleashed vast quantities of capital and financial resources in other countries while most of those same resources remain on the sidelines in California and throughout the US.

4. The RAM pricing proposal substantially risks abuse of the process through collusion and/or underbidding to manipulate prices (market signal), and auction results. The current market is small with only a few large players, which makes collusion and manipulation feasible and likely. Such manipulation could mortally damage the Commission's FIT program.

5. A reverse auction pricing mechanism is contrary to the proven pricing mechanisms of all successful FITs worldwide. Furthermore, it does not take advantage of the vast quantity of empirical evidence other countries have with successfully implementing cost-based FITs. By implementing an untested mechanism the Commission risks overall program failure due to unforeseen consequences and thus risks all of the stated goals. In fact, the RAM proposal increases the likelihood that legislative action will be required as the policymakers in Sacramento are losing patience with the CPUC's RPS failure and are ready to institute a system that has proven to be cost-effective, and produce reliable resutls, throughout the world.

    a. The official CEC recommendation from Dec 1, 2008 states that "The CPUC should immediately implement a feed-in tariff program for all RPS-eligible generating facilities up to 20 MW in size. Such a program should include must-take provisions as well as **<u>cost-based technology-specific prices</u>** that generally decline over time and are not linked to the CPUC's market price referent." With this, the CEC is officially recognizing the superiority and track record of cost-based FITs and this stance will encourage legislators to further "fix" the system. The cost-based pricing can price the energy at the market rate and the RECs separately so as to avoid any PURPA issues. Alternatively, the FIT program can be voluntary, but with real RPS penalties that encourage utilities who are failing to achieve their RPS requirements to participate in the voluntary FIT program.

6. As mentioned above, the RAM proposal provides a mechanism for ostensibly competitive pricing. However, there are several reasons why it would fail to create a truly competitive, efficient marketplace:
    A. There is no efficiently functioning power market in California because power is primarily produced by monopoly suppliers and prices are set by regulators, not

the market. Competition is not yet robust and sustainable and it is vigorously resisted by the monopoly IOUs at every opportunity.

B. The distributed generation market in California is very immature, volumes are tiny, price signals are opaque and not publicly available, and the market has not reached significant economies of scale; i.e. project volume is extremely thin at this time.

C. As proposed, prices of winning bids would not be made public so clear price signals would still not be received by the markets for manufacturing, investment, electricity, installation, etc., Effective markets contain clear, publicly available, and frequent price signals.

D. Large projects would be unfairly favored by the auction process which would result in a majority of the potential distributed generation projects being excluded from the program. The distributed generation market is much bigger than would be represented by only the larger projects.

Truly competitive market conditions do not yet exist for the distributed market and the RAM mechanism would unduly favor large projects, large existing developers, and the southern regions of the state. Therefore, it is unreasonable to conclude that projects contracted via the RAM mechanism would equate to an actual market pricing mechanism.

7. The RAM pricing mechanism is inherently unfair to require of solar IPPs, but not the IOUs, which as evidenced by the approval of SCE's solar PV program, will be allowed to enjoy the advantages of cost-based pricing; and double-dipping returns since they also get to ratebase the capital expenditures of building the utility-owned generation. RAM would establish an unlevel playing field for solar IPPs because it would require them to use an auction-based pricing mechanism while the competing IOUs get predetermined cost-based pricing combined with double-dipping returns. The IOU solar FIT programs and the Commission's FIT program should use the same pricing mechanism.

3. If you have specific modifications to the staff proposal, please provide a rationale for the modifications pursuant to the guiding principles.

1. Facilitate interconnection: Recent analysis found that approximately 69% of the California IOU substations can interconnect distributed RE projects of 10 MW or smaller.[5] Another study by GE examined the effect of DG on feeders and found that limits could range from 15% to 50% of feeder capacity depending on the location of the DG along the feeder, and how it was distributed.[6] For the Commission's FIT program to be effective it is essential that each IOU:
    a. Identify the total capacity of all substations and distribution feeder line segments on their distribution network.
    b. Identify capacity that has been allocated (approved but not connected) at every substation and feeder line.
    c. Identify capacity that has been queued but not yet allocated at every substation and feeder line.

d. Specify remaining available capacity at every substation and feeder line.
e. Utilize clearly written, "Fast Track" interconnection screens (FERC SGIP is a good example of such screens[7]) so developers can understand ahead of time what is required to interconnect projects under consideration.
f. Be required to utilize interconnection processes that are simple, economical, transparent, and pre-defined; ie, utilize interconnection processes that preempt any surprises.
g. Either neutralize network upgrade costs from the process by ratebasing these costs or by having them be adders to the winning bid prices. Alternatively, indicate estimated network upgrade costs for each substation and distribution feeder line location up to stated available capacity levels at each interconnection point.
h. Require IOU's to make all this information publicly available online in real time.

2. Interconnection Data: A good example of the needed interconnection data are the reports that the Ontario Power Authority has made available to support their recently improved FIT program. OPA provides easy access to two reports that enable prospective project developers to analyze the feasibility of interconnecting projects at specific substations and distribution feeder lines. The first report shows the capacity of all substations and feeder lines on their distribution network.[8] The second report shows all allocated capacity at each substation and feeder line.[9] Prospective project developers can easily determine interconnection feasibility and approximate network upgrade costs at any potential connection point by finding total capacity for that point on the first report and subtracting allocated capacity at the same point from the second report. Ontario utilities are required to update the reports weekly. Both reports are included in Appendix A and Appendix B for easy reference.

    This information is essential for prospective developers of projects in the in the 20MW-and-under range; and certainly for the 10MW-and-under range. In addition, Vermont has done an excellent job of introducing a comprehensive queuing process that leverages the Federal Energy Regulatory Commission (FERC) Small Generator Interconnect Procedure (SGIP). We have provided a flow chart in Appendix C for easy reference that is based on the Vermont queuing process and shows a viable pathway to incorporate queuing into any WDG FIT process.

    The FIT Coalition recommends that the Commission require each IOU to prepare and maintain an Interconnection Data Report that is updated in real-time, upon any new projects being queued, showing information about distribution level interconnection points including:

    a. The total capacity, allocated (contracted) capacity, queued capacity, and available capacity for ALL their substations and ALL their distribution feeder lines in California.
    b. An indication of estimated network upgrade cost ranges at each substation and feeder line shown in the report for interconnections within indicated available capacity. Suggested cost ranges per MW:
        i. $0 to $100K.

        ii. $100K to $250K.
        iii. More than $250K.
    c. An online map clearly showing the location of each substation and feeder line using the same identifier as listed in their "distribution connection report." This will enable prospective developers to focus site control on locations that will have economically viable interconnections, which will minimize inefficiencies and maximize value for ratepayers. A Google Maps overlay will be an easy method to meet this requirement.

    Every IOUs interconnection data report should follow a pre-defined format stipulated by the Commission so that each IOU's report is consistent. A sample report format has been included in Appendix D. In order to access the reports and maps, prospective program participants should be required to register at a website by providing basic identification information. This follows the experienced process that has been implemented in the recently improved Ontario FIT program. The IOUs must be required to keep the information in the online reports and maps updated in real-time.

    We cannot overstate the importance of this essential element. Most WDG projects in the 10MW-and-under range cannot be economically developed without having easily available data on interconnection locations that will result in reasonable and predictable network upgrade costs. Hence, the ready availability of this data is essential to the success of any simple, fair, and effective FIT program; unless the network upgrade costs are ratebased or otherwise neutralized.

3. Developer concentration: The amount of any single bidder's or equipment manufacturer's cumulative bids won should not be allowed to exceed 20% of total capacity at any auction event. This will foster development of a broader base of IPPs which will create a more competitive market and ultimately more cost effective pricing for ratepayers. Allowing bidders to win up to 50% would make it relatively easy for two players (e.g. two large vertically-integrated manufacturer-developers)to win most or all of any auction's capacity. The Commission should start out with rules that encourage competition rather than concentration. These rules can be modified over time if deemed necessary for some empirically-justified reason (more than 20% drop-outs etc).

4. Minimum project size: The WDG market segment includes projects ranging from tiny (< 100kW) to small (< 20 MW). Since it is clear that IOU resistance to FITs will increase with project size, the FIT Coalition supports the staff proposal to establish different procurement processes for projects in the 10 to 20 MW range, and we believe that the RAM process is more viable for projects larger than 10 MW. In addition, it is vitally important to recognize that it would artificially restrict the program to set the floor at 1 MW. We recommend that the minimum project size be set at 100 kW. Since a project can only connect on one side of a customer meter or the other, the FIT program will be completely separate from the California Solar Initiative (CSI) or any other net metering program. Without this lower minimum project size, however, perfectly feasible projects that don't make sense under CSI (non-owner occupied and/or split metered facilities, large roofs with small loads, etc) would be precluded from participating in a FIT program that is perfectly-suited to unleash this otherwise orphaned renewables potential. These smaller projects comprise a very large

proportion of the technical potential of customer-located renewables so it is imperative that they be included in the Commission's FIT program.

5. Location: It is anticipated that solar projects will represent a significant amount of the generation developed under this program. To make the RAM process fair for solar projects, the Commission's auctions should group bidders for solar projects into three geographic regions (north, central, and south) to recognize the variations in solar resources. Otherwise solar projects in the south will have an unfair advantage and prevent many suitable locations further north on the distribution grid from being developed. If the RAM mechanism's rules unduly favor any specific region there will be an unfair geographic imbalance in stakeholders' interests.

6. Auction capacity: Effectively utilizing the full range of available capacity on the distribution grid requires that the Commission make its program available to a broad range of project sizes. As indicated above, this range of project sizes should range from 100 kW to 20 MW. The 10 MW to 20 MW segment can be adequately addressed by a RAM process. However, efficient utilization of the segment below 10 MW definitely requires modification to staff's proposal. Without these modifications, only the largest players and projects will win in the bidding process because of their inherent economies of scale. This seems positive on the surface if cost is the only consideration. However, deeper analysis reveals that if only large projects can participate, the program will fail to meet all of the following goals of the Commission:
    a. Goal 3. "Focus on projects of a certain size that can effectively mitigate the market and regulatory constraints (such as site control and permitting) that slow down development of larger renewable projects." Projects in the 2 MW to 10 MW range are still very substantial projects so they will face much more challenging development cycles (frequently longer than 18 months) with respect to site control, location, design, permitting, construction, interconnection, etc. Smaller projects can be developed more quickly due to their inherent simplicity. The program needs to establish a mechanism to support the entire range of Wholesale Distributed Generation projects.
    b. Goal 7. "Adopt program design elements and a contract that adequately address project viability." If the program favors only the largest projects it would have a bias that unfairly renders smaller projects impractical. In so doing, it could unintentionally make project viability for smaller projects even more difficult than under the current undesirable situation via the RPS RFO process.
    c. Goal 8. "Facilitate interconnection of projects that efficiently utilize the existing distribution system. If large projects are unfairly favored, the program will fail to "efficiently utilize" the full range of capacity available on the distribution system." Instead, only a small slice of capacity will get utilized while a large remaining portion of the available capacity on the distribution system will be orphaned, wasting those potential benefits, including customer-sited WDG that carries that greatest Locational Benefits (LBs) for ratepayers.
    d. Goal 10. "Provide sufficient regulatory certainty to create a sustainable marketplace for small distributed generation renewable developers." If the largest developers and

projects are favored, the program will definitely fail to "create a sustainable marketplace for small distributed generation renewable developers."

We recommend the following modifications in order to avoid the program defects delineated above:

a. 75% of the FIT/RAM program capacity should be reserved for projects smaller than 10 MW so that larger projects cannot consume the entire available capacity of each auction.
b. Auction capacity should also be reserved for each of the geographic regions mentioned in recommendation number 6 - "Location" directly above. Since the Commission's FIT program is targeted at distributed generation, the amount of capacity reserved for each region should be based on the amount of electricity used in each region. This information can be easily found at the California Energy Commission's website.
c. Auctions for projects smaller than 10 MW should also be separated into tiers by the following size ranges:
    i. 100 kW to 1 MW
    ii. 1 MW to 5 MW
    iii. 5 MW to 10 MW
d. Auction capacity should be reserved for each of the above size ranges in order to give the broadest group possible of developers and projects the opportunity to participate in the program. If any available capacity is not successfully auctioned that amount of capacity should be added to the subsequent auction until all capacity is allocated for each region. There would be five auctions, one for each size range for each region, for a total of 15 auctions each time. We propose that the following percentages of each geographic region's total auction capacity be allocated by project size as follows (Commission could adjust these percentages):
    i. 100 kW to 1 MW --------------- 20%.
    ii. 1 MW to 5 MW ------------------- 30%.
    iii. 5 MW to 10 MW ----------------- 50%.
e. A spreadsheet is provided in Appendix E shows how the total auction capacity target could be apportioned to include region and project size considerations. Please refer to this spreadsheet to see the actual apportionment calculation.

7. Project diversification: The proposed structure's preference for large projects means the reliability of service delivery would potentially be more volatile because the power delivered would be distributed over a smaller number of larger projects rather than from a broader base of smaller projects. This could also complicate load balancing and reliability. Larger projects also inherently take longer to develop so it could delay reaching program volume targets. Lastly, a smaller group of larger projects means failure to complete implementation of any project would have a larger negative impact on overall capacity goals. The PUC needs to encourage structures that facilitate smaller projects and more broadly diversifies the risk of project implementation and/or service delivery failures.

8. Program Cap: The proposed program cap should be increased from 1 GW over four years to 4 GW over the same timeframe. In 2008 the amount of generation in California that could be

connected at the distribution level was estimated to be over 27 GW, and it is estimated to double to over 40 GW by 2020.[10] Assuming only 20 GW of capacity, consuming it at 250 MW per year would take 80 years. That would be a poor way to capitalize upon the most immediately available potential solution to California'sRPS mandates. Increasing the cap to 1 GW per year would enable the program to make a more meaningful contribution to the RPS mandates. Raising the cap would allow a larger and more immediate positive economic impact upon California in terms of job creation, desirable economic activitity, and tax revenue growth. It would accelerate California's ability to scale renewables, which directly maximizes competition and minimizes ratepayer costs (goal 2). In addition, it is clear that accelerating the achievement of a sustainable marketplace (goal 10), and allowing economic efficiencies to be reached sooner (goal 13) are desirable goals; as stated in the Commission proposal.

9. Must-take Contract: The FIT Coalition recommends usage of PG&E's AB 1969 contract since it is the shortest and most manageable available contract. It is important that the Commission take responsibility to create a single statewide contract as there is no reason to have multiple contracts throughout the State of California; and doing so would simply add inefficiencies, potential market barriers, and ultimately drive costs higher for ratepayers.

4. If RAM is not your preferred pricing mechanism, please provide an alternative proposal that addresses the guiding principles and how your proposal results in the procurement of viable and low-cost projects within a capped program.

1. Use fixed FIT prices that are:
    A. Cost-based.
    B. Technology-based.
    C. Project size-based

   Attachment A to staffs' System-Side Renewable Distributed Generation Pricing Proposal[11] states that "The key aspect of this mechanism is that the policy provides a long-term investment signal." Using fixed prices based on the three criteria above is undoubtedly a better way to meet the "key aspect" of the pricing mechanism than a reverse auction mechanism where prices of winning bid are not made public. In addition, including technology criteria is a better way to meet the Commission's goal 1 "Be open to all RPS-eligible technolgies…" because it provides a clearer price signal for all technologies rather than simply taking the lowest bids using any technology. It is also a better way to meet goal 5 of maximizing transparency. In addition, including project size criteria will better meet goal 3 of focusing on projects of a size that can effectively mitigate the market and regulatory constraints because it will facilitate projects of all sizes rather than favoring just the larger projects. Lastly, goal 10, "providing sufficient regulatory certainty to create a sustainable marketplace" would be more effectively met because this approach is more transparent to all stakeholders.

2. The Commission should contract one or more truly independent consulting organizations to annually compute the subsequent year's cost-based FIT prices. This is the best way to

ensure that the optimal balance of stakeholder interests is reflected in the FIT prices. This is also an established and proven way to set annual cost-based FIT prices.

3. As stated in question 3 above, raise the program cap to 4 GW with a minimum of 1 GW auctioned per year instead of a 1 GW cap over four years.

4. Include language defining a price adjustment mechanism in the FIT that adjusts prices for the subsequent year based on the amount of over or under-subscription to the previous year's volume target. (The FIT Coalition would be happy to provide detailed language for such a price adjustment mechanism if the Commission is interested.) This would more effectively minimize ratepayer costs (goal 2) and establish just and reasonable rates for buyer, seller, ratepayer, and society (goal 11) because rates would be under the direct control of the Commission and could be adjusted annually according to performance, versus leaving rates up to an auction process in an underdeveloped, noncompetitive market which could be manipulated by large players.

5. Use the interconnection recommendations detailed in our response to question 3 above.

6. Require IOUs to accept interconnection as long as the project meets all the program's defined interconnection requirements. Use of Ontario-style pre-identification of preferred interconnect locations and Vermont-style queuing via FERC SGIP Fast Track screens or something similar to determine acceptable interconnection requirements. This would enable simplification of the interconnection agreement which would go a long way towards goal 4, "minimize the transactions costs for the seller, buyer, and the regulator." It would also contribute to goal 12, "Simplicity."

7. Consider abolishing the requirement for a PPA between the IPP and the IOU by incorporating the necessary language into the regulation and requiring that, once the IOU and IPP agree in writing that all other required conditions have been met (interconnection agreement), the IOU simply pays the IPP the price applicable under the regulation. This is a much more efficient and cost effective process for all stakeholders and it has been shown to work very effectively in Germany's FIT program.. Doing this would meet goal 4, "minimize the transaction costs for the seller, buyer, and the regulator" and it would also contribute substantially to goal 12, "Simplicity." It seems a bit radical at first, but it is actually a simple change and it has been proven to work effectively.

8. All documents, agreements, processes, definitions and terms used in the program should be pre-defined to the extent possible, and as efficient and transparent as possible. Again, this would meet goal 4, "minimize the transactions costs for the seller, buyer, and the regulator" and goal 12, "Simplicity." A list of the agreements, processes, and terminology that should be defined by the program follows:

   A. Documents and Agreements.
      i. Application Form.
      ii. Interconnection Agreement.
      iii. Technical Requirements.

iv. Operator Protocols.
v. Codes and Standards.
vi. Feasibility Study Agreement.
vii. System Impact Study Agreement.
viii. Facilities Study Agreement

B. Processes
i. Application process.
ii. Notifications process.
iii. Site Control process
iv. Interconnection Queue Management process.
v. Application modification process.
vi. Applications Eligible for Fast Track process.
vii. Fast Track Screening Criteria and process.
viii. Applications Not Eligible for Fast Track process.
a. Feasibility Study process.
1. Feasibility Study Preparation process.
2. Feasibility Study Report and Cost Reconciliation process
b. System Impact Study process.
1. System Impact Study Preparation process.
2. System Impact Study Report and Cost Reconciliation process.
c. Facilities Study process.
1. Facilities Study Preparation process.
2. System Upgrade process.
3. Cost Reconciliation process.
4. Facilities Cost Responsibility process.
ix. Certification of Generation Resource Equipment process.
x. Interconnection process.
xi. Facilities Grouping process.
xii. Equipment Testing process.
xiii. Interconnection Metering process.
xiv. Disconnection process.
xv. Annual FIT Price Adjustment process.
xvi. Annual FIT Price Degression process.

C. Definitions and Terms (examples provided but this is not exhaustive).
i. Application.
ii. Automatic Disconnect Device.
iii. Disconnect.
iv. Emergency.
v. Facilities Study.
vi. Fast Track.
vii. Fast Track Screening Criteria.
viii. Feasibility Study.
ix. FERC.

x. Generation Resource.
xi. IEEE.
xii. Interconnecting Utility.
xiii. Interconnection Agreement.
xiv. Interconnection Facilities.
xv. Interconnection Requester.
xvi. Interconnection Queue.
xvii. Operator Protocols.
xviii. Point of Interconnection.
xix. Radial Feeder.
xx. System Impact Study.
xxi. System Upgrades.
xxii. Technical Requirements.

5. Staff has proposed a soft 1000 MW interim target over the next four years, which needs to be converted into a revenue requirement. Please propose a methodology to calculate the revenue requirement based on the 1000 MW interim target. Parties should address, at a minimum:

An overall program cap determined by a revenue requirement runs counter to the stated goals of a long-term price signal and a sustainable marketplace. Because winning prices are not known ahead of time, there is no certainty regarding how much of the overall revenue requirement each auction will fulfill. Therefore, since developers have no way to predict how much capacity will be available in future auctions, there is no long-term price signal or stable marketplace. Instead of a revenue requirement, program caps in the system should be based on contracted capacity. Each auction should specify the exact amount of generation capacity that is available. This would send a clearer market signal that would encourage more effective market development.

6. Additional comments regarding the Energy Division FIT pricing proposal.

We feel it is critically important to target effective policy at the distribution market segment because:

1. The distribution segment bypasses the large and unpredictable time delays associated with projects that rely upon the transmission network.
2. There are substantial cost savings for ratepayers to be realized by locating and interconnecting projects on the distribution network close to where the power is used rather than utilizing the transmission grid. In fact, it is estimated that the locational benefits of distributed generation energy make it 35% more valuable than energy produced at large central power stations and transmitted over the transmission grid.[12]

The WDG market segment has the greatest potential to bring renewable energy sources online quickly in volumes that can actually meet the RPS mandated quantities and schedules. The amount of generation in California that could currently be connected at the distribution level is over 27 GW.

C. Pricing Structure Issues (Attachment B)

Responses to the questions set forth in Attachment B regarding FIT price structure (rate design) are set forth below.

1. Who are the stakeholders with respect to the FIT?

1. Ratepayers.
2. Children and Future Generations.
3. California's Residents (Atmosphere and Environment).
4. California's 2.3 Million Unemployed Residents.
5. RE Equipment Manufacturers.
6. IPPs.
7. Installers.
8. IOUs & LSEs.
9. PUC.
10. CEC.
11. California's Government (Executive, Legislature, Judiciary).
12. California's Taxpayers.
13. California's Debt Holders.
14. California's Fish and Wildlife.
15. California's Water Resources

2. What are the interests of those stakeholders relative to the FIT?

1. Ratepayers.
   California's ratepayers have an interest in stable and dependable electricity and electricity rates. Renewable energy sources can deliver price stability because their fuel is free. Renewable energy sources can deliver cost-effective electricity when brought to scale. Renewable energy sources can deliver savings to ratepayers after the point at which rates for conventional power exceed rates for renewable power. This inflection point should be reached in approximately 2014 if an effective distributed market FIT is implemented soon.[13] Another crucial effect that needs to be accounted for in this analysis is the "Merit Order Effect." This effect is described as the fuel cost savings that are realized when conventional power is replaced by renewables. The Merit Order Effect accelerates the cost savings for ratepayers and can shorten attainment of the inflection point between conventional power costs and renewabbles costs to as little as one year.[14] Ratepayers should be freed from volatile, unpredictable, and ever-increasing fuel costs. Ratepayers have an interest in developing clean energy sources to replace California's dirty generating facilities.

2. Children and Future Generations.

California's children and future generations deserve a sustainable energy infrastructure the doesn't pollute their environment, leaves them a planet that is as healthy as the one current generations have enjoyed, frees them from the expensive and dangerous responsibility of securing foreign energy sources, and leaves them with a healthy and sustainable industry that produces jobs and prosperity for them and the state.

3. California's Residents (Atmosphere and Environment).
   The entire population of California has an interest in having the cleanest air and environment possible.

4. California's 2.3 Million Unemployed Residents.
   The state currently has the second highest unemployment rate in the nation, behind only Michigan. California's unemployed people all have an interest in the state government providing them with policies that generate jobs in healthy and sustainable industries.

5. RE Equipment Manufacturers.
   RE equipment manufacturers have a direct interest in the state government establishing policies that enable them to scale their technologies so they can compete on a worldwide basis with their large European and Asian competitors. If California does institute such policies soon these markets and the jobs, income, living standards, and tax revenue that go with them will be lost to the foreign competitors who are already taking the majority of the global business volume. California needs to wake up and support its RE industry before it is too late.

6. IPPs.
   California could quickly create a huge and robust RE development business if it would establish a policy framework to unleash all the technical, business, and financial interests that want to become active in the business of manufacturing, building, financing, and operating distributed RE generating facilities.

7. Installers and Labor.
   The state is full of talented installation businesses and installation experts who are currently fighting over very small volumes of projects because the state has failed to support the WDG market segment. A huge number of installers could quickly become active and productive if WDG is allowed to develop through well designed FIT policies.

8. IOUs & LSEs.
   IOUs and LSEs need to meet aggressive RPS mandates. No meaningful progress has been made towards the mandate in the past seven years and it is clear that the state will fail to attain the 2010 20% mandate. Policy innovations are more important that technology innovations in order to turn this failure around. New and improved policy actions will be needed in order to make the RPS mandate a reality. Well designed FITs are the obvious solution. California needs to learn from the many countries and regions around the world that have seen success in bringing unparalleled levels of renewables online via FITs and follow their example rather than trying to succeed by implementing

unproven, experimental policies and then giving them more time to see what happens. While it is natural for the IOUs to resist competition from new power generators, it is the job of the CPUC to implement sensible and effect policy that will achieve California's RPS mandates.

9. PUC.
   The PUC has a strong interest in seeing that their FIT program is a strong success or there will be ever increasing political support for a sweeping legislative mandate. A legislative solution that forces the PUC to act would not be in the PUCs self interest. Clearly, the PUC also has a strong interest in seeing that ratepayers are charged the lowest rates possible for electricity and are provided with stable and reliable power supplies; while achieving RPS mandates.

10. CEC.
   In terms of influence and responsibility for RE, the CEC's interests are to meet RPS objectives on schedule and cost-effectively via policy innnovations. The CEC has already made clear its belief that a 20MW-and-under comprehensive FIT is the proper approach; via a cost-based pricing mechanism and a standard must-take contract.

11. California's Government (Executive, Legislature, Judiciary).
   The state's government has an interest in being perceived as effective. So far, California has little to support its claim of being a leader on RE policy and development when compared with many other countries, and now an emerging group of other US states and local governments as well. If California's government wants its voters to perceive it as effective on RE policy it has a very short window in which to pass more effective FIT policy before it becomes glaringly apparent that California is a laggard in this area.

12. California's Taxpayers.
   The taxpayers of California have an extremely strong interest in finding a way to stimulate the economy and decrease the pressure for increased taxes. Well designed FIT policies targeting specific RE market segments could generate a RE industry and jobs boom in the state that is sustainable and doesn't require any public borrowing or additional increases to the state's debt obligation. Energy is the largest industry in the world. A comprehensive FIT is by far the most economically promising energy policy opportunity available to the state. The state urgently needs to take advantage of this opportunity

13. California's Debt Holders.
   Holders of California bonds would love to see the state get back on more solid financial ground. Driving and supporting a robust RE industry is the best single opportunity to make this happen. If the state does not get back to an improved financial position soon the value of California's debt may substantially decrease as lenders require ever higher interest rates to be willing to lend money to the state.

14. California's Treasury.

Lenders will drive California's borrowing costs up dramatically if the state does not find a way to improve its financial position soon. If that happens the state Treasury will have to pay a rapidly increasing proportion of its revenue as interest cost on the debt. Therefore, the state Treasury has a strong interest in seeing effective new economic polices that can move the state back towards healthy economic conditions without additional public borrowing.[15] An effective WDG FIT program is the best opportunity to bring the economy back to health and avoid higher state borrowing costs.

15. California's Fish, Wildlife, Trees, and Plants.
California's incredible natural wealth of fish, wildlife, trees, and plants is completely reliant upon a healthy natural environment and stable environmental conditions for its survival. Developing the ability to replace dirty generating facilities, and potentially many hydro facilities, with clean and sustainable RE would be a tremendous benefit to the safety and well-being of the state's flora and fauna.

16. California's Water Resources
Global warming threatens the state with increasingly volatile precipitation causing more frequent and extreme drought and flood conditions, and possibly permanently decreasing the amount of water available for the entire state. The state should be implementing more effective FIT policies to safeguard our water resources and all the people, wildlife, and plants that depend upon them.

3. What price components may be used in various pricing approaches and structures, and what are the advantages and disadvantages relative to each price component?

The most effective price components to use are Energy Rate (cents/kWh) with Adjustments in the context of FIT pricing which is cost-based, technology-based, and location-based. By adjustments we do not mean adders. Instead, adjustment means adjusting prices annually to account for actual demand as demonstrated by the prior year's results and adjusting for changes in costs of the technology and changes in other costs of development such as financing and installation costs.

A built in degression rate is helpful and essential but an additional annual price adjustment mechanism is also required. This mechanism typically takes the form of a FIT price reset based on cost decreases from the prior year and another adjustment based on actual demand experienced at the prior year's prices. The price paid to IPPs should be fixed for the duration of each agreement (20 years or more). Price adjustments for subsequent years should only be applied to new projects applying within that same year. The advantage of this mechanism is it provides the clearest possible price signal to the market and it creates the greatest degree of certainty to stimulate scale and sustainability.

If the Commission moves ahead with a reverse auction-based pricing mechanism then the price components become superfluous since prices will be set by reverse auction and will not be publicly available information. It must be noted that experience has demonstrated that the proposed auction mechanism with a cap is a substantially inferior method of promoting market development and it is very possible that it could actually create the unintended consequence of higher rates for ratepayers.[16] The one cost component that could be separated under a RAM-type approach is the network upgrade costs, which could be neutralized by ratebasing them, or having them as adders on top of the winning bid prices that would not include the relatively unpredictable network upgrade costs.

4. What is the best combination of price components to meet stakeholder interests?

The least risky and best combination of price components to meet stakeholder interests are Energy Rate (cents/kWh) with Adjustments in a cost-based, technology-based, and location-based FIT pricing mechanism.

5. If there are competing stakeholder interests, what is the best combination of price components to reasonably balance competing interests.

The IOU interests will always be to protect their businesses from competition, but this is counter to virtually all other stakeholders' interests; and to the objectives of a FIT program and the fulfillment of RPS mandates. It is clear that the Commission needs to conduct its policymaking above the IOUs' interests, and the Commission needs to focus on the following:

1. Ratepayers' interest in low and stable rates.
2. Protecting the atmosphere and environment.
3. Leaving a sustainable and clean energy infrastructure for future generations.
4. Allowing IPPs to build a robust and sustainable distributed RE industy.
5. Scaling the equipment manufacturers so that they can drive costs down and compete on a global basis.
6. Building a strong and sustainable installation industry.
7. Allowing IPPs to grow the distributed market quickly enough to create a large number of new, well-paying jobs for California's 2.3 million unemployed workers.

The best combination of price components to optimally balance stakeholder interests are Energy Rate (cents/kWh) with Adjustments in a cost-based, technology-based, and location-based FIT pricing mechanism.

6. Discuss whether or not the Commission should state a preference for certain price components and price structures to be used in a Commission-adopted FIT. If so, identify and discuss which components and structures should be preferred by the Commission.

As stated above, the optimal balance of stakeholder interests is met by utilizing the price components of Energy Rate (cents/kWh) with Adjustments (as described above) in a cost-based, technology-based, and location-based FIT pricing mechanism.

7. Discuss whether or not the Commission should require certain price components and price structures to be used in a Commission-adopted FIT. If so, identify and discuss which components should be required by the Commission.

The Commission should require the price components of Energy Rate (cents/kWh) with Adjustments (as described above) in a cost-based, technology-based, and location-based FIT pricing mechanism because this would send the clearest market price signals, most effectively develop a sustainable market, and yield the optimal balance of stakeholders' interests.

8. State anything else that is material and relevant to the issue of pricing structure (rate design) for a Commission-adopted FIT.

In addition, please comment on the following specific examples for a twenty year contract. Each example applies to any FIT pricing approach (e.g., price based on seller's cost, buyer's avoided cost, auction, bi-lateral negotiation, other).

9. Example A: If the sole or primary interest is to ensure cost recovery for the project, the optimal payment may be a lump sum at the commercial operation date. Please comment.

There is built-in protection for the ratepayers to match energy payments with energy deliveries. Unless the Commission plans to monitor WDG power plants for 20 years, then upfront payments are not worth discussing. The only exception would be a partial buy-down to help emerging RE technologies to be competitive in the otherwise per kWh-based approach.

10. Example B: If the project has both fixed and variable costs and the sole or primary interest is to ensure cost recovery for the project, the optimal payment may be a lump sum at the commercial operation for the fixed costs and payment of variable costs as incurred over time. Please comment.

There is built-in protection for the ratepayers to match energy payments with energy deliveries. Unless the Commission plans to monitor WDG power plants for 20 years, then upfront payments are not worth discussing. The only exception would be a partial buy-down to help emerging RE technologies to be competitive in the otherwise per kWh-based approach.

11. Example C: Assume that the primary interests are revenue certainty for the seller, conservation (i.e., optimal use of resources), efficiency and equity. Assume that the selected payment structure is a combination of fixed (e.g., dollars per month) along with demand and energy prices; the demand price (dollars/kW per month) is at a fixed level (dollar amount) in the contract for the life of the contract and paid upon performance (delivery); the initial energy price (cents/kWh) is fixed in the contract, payment varies by time of delivery (TOD) based on TOD factors, is paid based upon performance (delivery), and the energy rate is adjusted to the market once every 5 years. Under this price structure, perhaps the fixed payment provides revenue security for the project; the demand and energy rates provide an incentive for *performance; and the periodic adjustment to the market provides assurance to both the project and ratepayers that prices never vary too drastically from current market realities while the seller's variable costs (to the extent they vary with the market) are recovered without over- or under-payment, thereby promoting efficiency and equity. Is this an optimal price structure? Please comment.*

The FIT Coalition feels that it has provided extensive price related recommendations in questions 3 and 4 above. We feel that further elaboration on pricing in a purely hypothetical context would not add value to our comments.

12. Example D: Assume the price structure is an energy payment only, and the initial average overall price is $0.25/kWh to be paid by TOD factors set in the standard contract. To balance competing interests (e.g., revenue security, conservation, efficiency, equity), assume the payment is 80% fixed and 20% variable. That is, $0.20/kWh is paid for each delivered kWh over the life of the contract. The remainder, $0.05/kWh, is paid the first 5 years, and is then subject to adjustment to reflect the current market (e.g., formula in the contract that based on an index to model seller's variable costs), and is adjusted again at years 10 and 15. The TOD factors are updated once at year 10 to align with the current TOD profile of the buyer. This price structure might satisfy several interests including (a) simplicity (i.e., based only on energy price), (b) providing some certainty to the seller of the payment type (energy only) and amount (with 80% fixed and 20% subject to adjustment), (c) payment upon performance (to provide the incentive to produce), (d) payment based on TOD (to provide the incentive to provide the product when needed), (e) an update to a portion of the price (to align with the market), (f) an update to TOD factors periodically (to align TOD factors with current market needs in order to give the seller an incentive to shift production, if possible, to the times the electricity is needed), and (g) revenue certainty for the majority (80%) of the payment (perhaps a benefit to the project) while aligning a portion (20%) of the total payment with the current "market" (a potential benefit to the project if the project has variable costs that vary with market conditions, and a potential benefit to ratepayers so the total payment does not get too far out of alignment with market realities). Please comment.

The FIT Coalition feels that it has provided extensive price related recommendations in questions 3 and 4 above. We feel that further elaboration on pricing in a purely hypothetical context would not add value to our comments.

13. Example E: Payment is made upon performance (i.e., an energy price paid in cents/kWh). Renewable technologies (with storage) that can guarantee on-peak energy are encouraged (e.g., photovoltaic with storage would receive a different FIT level of payment than photovoltaic without storage). To avoid over payment/under payment, FIT price levels are revisited annually and revised according to the amount of energy delivered. Revised prices apply to new contracts, but not existing contracts. If the amount of new FIT generation exceeds 2 percent of retail sales, FIT price levels should drop by 10 percent. Please comment.

The FIT Coalition feels that it has provided extensive price related recommendations in questions 3 and 4 above. We feel that further elaboration on pricing in a purely hypothetical context would not add value to our comments.

14. Other examples: Please provide other reasonable examples and explain whether or not the Commission should consider or adopt elements of those examples.

The FIT Coalition feels that it has provided extensive price related recommendations in questions 3 and 4 above. We feel that further elaboration on pricing in a purely hypothetical context would not add value to our comments.

Finally, please address:
15. Based on a consideration of the range of stakeholder interests, various candidate price components and examples, please state the specific price structure (rate design), if any, you recommend be adopted by the Commission.

The Commission should require the price components of Energy Rate (cents/kWh) with Adjustments (as described in question 4 above) in a cost-based, technology-based, and location-based FIT pricing mechanism because such a structure would yield the optimal solution for balancing stakeholders' interests.

If the Commission chooses to use the RAM pricing mechanism then we recommend it include modifications per our comments in question 3 above.

D. Pricing-Related Goals of an FIT (Attachment C)

E. Assessment of Recommendations on FIT Pricing (Attachments D and E)

F. Proposal to Take Official Notice of California Energy Commission FIT Final Consultant Report

We are not clear which specific Consultant Report the Commission is referring to in this question. We are aware of a report from Navigant Consulting to the California Energy Commission's Public Interest Energy Research Program (PIER) dated August 11, 2009, titled "Distributed Renewable Energy Assessment."[17] Since the Commission's FIT program is targeted at the distributed generation market, we recommend that the Commission take official notice of the California Energy Commission's Final Consultant Report on this subject.

This report assess the potential for "distributed energy resources (DRE)" to contribute to California's 33% RPS mandate. It contains valuable and helpful information including:

1. How to assess the potential of distributed generation energy in California.
2. Constraints to development of distributed generation.
3. An analysis of the potential of various DRE technologies.
4. Which technologies have the greatest near-term potential.
5. An analysis of the distribution systems capacity in California.
6. How to calculate the distribution system's capacity for additional DRE.
7. An estimate of how much DRE could be connected at the distribution level in 2008.
8. A forecast of how much DRE could be connected at the distribution level in 2020.
9. Key findings.

We respectfully call the Commission's attention to this report for consideration.

We would also like to highlight the recent RETI report which addresses the dramatically falling cost of PV and how it could contribute to meeting the 33% RPS target. RETI conducted a sensitivity analysis for meeting the 33 percent renewables target primarily with distributed PV and identified 27,500 MW of distributed PV potential that could produce 58,775 GWh per year.[18] The RETI report states that the $3,700/kWe PV price assumption makes 45,000 GWh of distributed renewable resources cost-competitive, the large majority of which are distributed PV resources.[19] For the sake of analysis all of this distributed resource should be assumed to be PV. This 45,000 GWh cost-competitive distributed PV resource is equivalent in size to the net short renewable energy gap identified by the CEC in June 2009 of 45,481 GWh.

G. Additional Material Information

See Appendices to our comments at end of this document.

III.
CONCLUSION

The FIT Coalition supports the implementation of a comprehensive cost-based FIT program addressing development of Wholesale Distributed Generation (WDG) in California. The potential of WDGto bring massive amounts of RE online quickly far exceeds that of both the net-metered market segment and the transmission-dependent central-station market segment. If implemented effectively, this program could have a tremendously beneficial impact upon RE development in California and the U.S.

The intent of our recommendations is to reach the optimal balance of stakeholders' interests while simultaneously stimulating rapid development of large amounts of RE. The overwhelming majority of empirical data on successfully implemented FIT programs shows, that the best way to do this is with:

1. Cost-based FIT prices that incorporate technology, location, and project size.
2. Comprehensive and publicly available data on interconnection points.
3. Standardized, predictable, and predetermined "interconnection processes.
4. Simple, pre-defined, and cost effective procurement processes.
5. Streamlined standard must-take agreements.
6. 20 years purchase terms.
7. Demand based price adjustment mechanisms, and automatic price degression.

The proposed RAM pricing mechanism introduces additional risks to the success of the program because of its unproven nature, the immature state of the yet-to-be addressed WDG market segment, and the lack of competition in the market. These additional risks include over-concentration of supply, auction manipulation, potential collusion, a preponderance of large projects, geographic concentration of facilities, exclusion of small and entry-level developers, exclusion of new-yet-promising technologies, lack of competition, higher eventual prices, lack of clear market signals, lack of equity and debt financing, constrained market development, inefficient utilization of the existing distribution system, and sub-optimal employment creation. We have proposed a list of recommendations to the RAM pricing mechanism which addresses these additional risks. We have also provided supporting documentation which we hope may be useful to clarify improvements that could be incorporated.

Regardless of the pricing mechanism used, it is imperative that the Commission's FIT program make a clear distinction between the rules and processes applied to large and small sized projects. We think 10 MW is a reasonable threshold for small projects; with a cost-based approach utilized below and a RAM approach utilized above. Applied correctly, this could establish a framework that enables successful participation of large and small players developing the complete range of project sizes required to fully utilize the entire available potential of the WDG market segment, which is unparalleled for at least the next decade due to the decades-long transmission build-outs required to get central station renewables online.

In closing, we support the Commission for its initial effort to unleash the WDG market segment. There is far more that needs to be done, and the FIT Coalition will continue to assist in guiding the Commission and all other policymakers towards simple, fair, and effective policy mechanisms.

ENDNOTES:

[1] Attachment A, System-Side Renewable Distributed Generation Pricing Proposal, Energy Division Staff Proposal - August 26, 2009 Page 7.
[2] Attachment C, Goals For FIT Price Structure, Energy Division Staff Proposal - August 26, 2009 Page 1.
[3] Attachment A, System-Side Renewable Distributed Generation Pricing Proposal, Energy Division Staff Proposal - August 26, 2009 Page 7.
[4] Ibid. Page 10.
[5] US Department of Energy, The Potential Benefits of Distributed Generation and Rate-Related Issues That May Impede Their Expansion, February 2007. Referenced analysis done by GE Corporate Research and Development, 2003.
[6] Ibid.
[7] FERC Small Generator Interconnection Procedures (SGIP) For Generating Facilities No Larger Than 20 MW, Section 2 – Fast Track Process, 2.2.1 – Screens, Page 3.
[8] Ontario Power Authority, Connection Availability Table – Station, October 2, 2009.
[9] Ontario Hydro One Distribution Connections Allocated Capacity List, October 14, 2009.
[10] Distributed Renewable Energy Assessment Final Report, Navigant Consulting, August 11, 2009, Public Interest Energy Research Program, California Energy Commission, Page 30.
[11] Attachment A, System-Side Renewable Distributed Generation Pricing Proposal, Energy Division Staff Proposal - August 26, 2009 Page 7.
[12] GreenVolts et al comments on 2008 MPR R0602012, and spreadsheet accompanying related presentations, March 6, 2008.
[13] FIT Coalition letter to the California Energy Commission, Re: Docket No. 09-IEP-1G/03-RPS-1078 June 11, 2009, Page 2.
[14] "Feed-in Tariff for Renewable Energies: An Effective Stimulus Package without New Public Borrowing." Hans-Josef Fell, Member of the German Legislature, March 2009, Pages 21 and 27.
[15] Ibid. Pages 12 - 14.
[16] Ibid. Page 8.
[17] Distributed Renewable Energy Assessment Final Report, Navigant Consulting, August 11, 2009, Public Interest Energy Research Program, California Energy Commission.
[18] RETI, Phase 1B draft report, November 4, 2008, p. 6-23.
[19] Ibid, p. 5-15 and p. 5-16.

Appendix A

Connection Availability Table - Station

Station Name	Bus Name	Available Station Capacity (MW)	Supply Circuit 1	Availability (MW)	Supply Circuit 2	Availability (MW)	Area	Area Limit (MW)
AGIMAK DS	Total	7	29M1	0			Northwest	100
AGINCOURT TS	Total	22	C10A	50	C4R	50	Central	Note 1
AGINCOURT TS	B	11	C10A	50	C4R	50	Central	Note 1
AGINCOURT TS	Y	11	C10A	50	C4R	50	Central	Note 1
ALBION TS	Total	11	M30A	0	M31A	0	East	1500
ALBION TS	BQ	5	M30A	0	M31A	0	East	1500
ALBION TS	JY	5	M30A	0	M31A	0	East	1500
ALLANBURG TS	Total	22	A6C	110	A7C	100	Central	Note 1
ALLISTON TS	Total	61	E8V	140	E9V	140	Central	Note 1
ALLISTON TS	T2	0	E8V	140	E9V	140	Central	Note 1
ALMONTE TS	Total	25	M29C	200			East	1500
ALMONTE TS	J	22	M29C	200			East	1500
ALMONTE TS	Q	25	M29C	200			East	1500
ANDREWS TS	Total	3	Gartshore 1	20	Gartshore 2	20	Northeast	300
ANJIGAMI TS	Total	15	Not expected to be limited by a supply circuit				Northeast	300
ARDOCH DS	Total	6	B1S	0			East	1500
ARMITAGE TS DESN 1	QJ	119	B82V	260	B83V	260	Central	Note 1
ARMITAGE TS DESN 2	EY	87	B82V	260	B83V	260	Central	Note 1
ARNPRIOR TS	Total	15	C7BM	0	W6CS	0	East	1500
AYLMER TS	Total	10	WT1A	70			West of London	150
BARRIE TS	Total	69	E3B	120	E4B	160	Central	Note 1
BASIN TS	Total	11	H1L	10	H3L	50	Central	Note 1
BASIN TS	A5A6	5	H1L	10	H3L	50	Central	Note 1
BASIN TS	A7A8	5	H1L	10	H3L	50	Central	Note 1
BATCHAWANA TS	Total	0	Sault 3	0			Northeast	300
BATHURST TS DESN 1	Total	84	C18R	50	P22R	50	Central	Note 1
BATHURST TS DESN 1	B	41	C18R	50	P22R	50	Central	Note 1
BATHURST TS DESN 1	Y	43	C18R	50	P22R	50	Central	Note 1
BATHURST TS DESN 2	Total	62	C18R	50	P22R	50	Central	Note 1
BATHURST TS DESN 2	J	28	C18R	50	P22R	50	Central	Note 1
BATHURST TS DESN 2	Q	34	C18R	50	P22R	50	Central	Note 1
BATTERSEA DS	Total	8	S1K	60			East	1500
BATTERSEA DS	T1	7	S1K	60			East	1500
BATTERSEA DS	T2	8	S1K	60			East	1500
BEACH TS - DESN1	Total	6	Not expected to be limited by a supply circuit				Central	Note 1
BEACH TS - DESN1	B1B2	0	Not expected to be limited by a supply circuit				Central	Note 1
BEACH TS - DESN1	Y1Y2	5	Not expected to be limited by a supply circuit				Central	Note 1
BEACH TS - DESN2	Total	8	Not expected to be limited by a supply circuit				Central	Note 1
BEACH TS - DESN2	J1J2	3	Not expected to be limited by a supply circuit				Central	Note 1
BEACH TS - DESN2	Q1Q2	5	Not expected to be limited by a supply circuit				Central	Note 1
BEAMSVILLE TS	Total	34	Q2AH	0			Central	Note 1
BEARDMORE DS	Total	6	A4L	0			Northwest	100
BEAVERTON TS	Total	72	M80B	70	M81B	70	Central	Note 1
BELLE RIVER TS	Total	7	K2Z	- (Note 2)	K6Z	- (Note 2)	West of London	150
BELLEVILLE TS	Total	80	B23C	350	H23B	250	East	1500
BERMONDSEY TS DESN 1	J	10	C14L	50	C17L	50	Central	Note 1
BERMONDSEY TS DESN 1	Q	11	C14L	50	C17L	50	Central	Note 1
BERMONDSEY TS DESN 1	T1T2	21	C14L	50	C17L	50	Central	Note 1
BERMONDSEY TS DESN 2	B	11	C14L	50	C17L	50	Central	Note 1
BERMONDSEY TS DESN 2	T3T4	22	C14L	50	C17L	50	Central	Note 1
BERMONDSEY TS DESN 2	Y	11	C14L	50	C17L	50	Central	Note 1
BILBERRY CREEK TS	Total	62	A2	40	H9A	50	East	1500
BIRCH TS	Total	64	Not expected to be limited by a supply circuit				Northwest	100
BIRMINGHAM TS DESN 1	BY	5	HL3	130	HL4	130	Central	Note 1
BIRMINGHAM TS DESN 1	QJ	5	HL3	130	HL4	130	Central	Note 1
BIRMINGHAM TS DESN 1	T1T2	11	HL3	130	HL4	130	Central	Note 1
BIRMINGHAM TS DESN 2	EZ	3	HL3	130	HL4	130	Central	Note 1
BIRMINGHAM TS DESN 2	KD	22	HL3	130	HL4	130	Central	Note 1
BIRMINGHAM TS DESN 2	T3T4	24	HL3	130	HL4	130	Central	Note 1
BLOOMSBURG MTS		Note 3	A1N	0			Central	Note 1
BRACEBRIDGE TS	Total	40	M6E	70			Central	Note 1
BRAMALEA TS DESN 1	B	5	V41H	50	V42H	50	Central	Note 1
BRAMALEA TS DESN 1	T1T2	11	V41H	50	V42H	50	Central	Note 1
BRAMALEA TS DESN 1	Y	5	V41H	50	V42H	50	Central	Note 1
BRAMALEA TS DESN 2	T3T4	0	V41H	50	V42H	50	Central	Note 1
BRAMALEA TS DESN 3	T5T6	0	V41H	50	V42H	50	Central	Note 1
BRANT TS	Total	62	B12	110	B13	110	Central	Note 1
BRANTFORD TS	Total	5	M32W	110	M33W		Central	Note 1
BRANTFORD TS	Y	5	M32W	110	M33W		Central	Note 1
BRANTFORD TS	Z	0	M32W	110	M33W		Central	Note 1
BRIDGMAN TS DESN 1	A1A2	5	L13W	10	L14W	10	Central	Note 1
BRIDGMAN TS DESN 2	LA1&LA2	5	L13W	10	L14W	10	Central	Note 1
BRIDGMAN TS DESN 3	LA6&LA5	5	L13W	10	L14W	10	Central	Note 1
BRIDGMAN TS DESN 4	LA7&LA8	5	L13W	10	L14W	10	Central	Note 1
BROCKVILLE TS	Total	39	L20H	100	L22H	100	East	1500
BRONTE TS DESN 1	Total	64	B7	130	B8	130	Central	Note 1

Station Name	Bus Name	Available Station Capacity (MW)	Supply Circuit 1	Availability (MW)	Supply Circuit 2	Availability (MW)	Area	Area Limit (MW)
BRONTE TS DESN 1	T5	54	B7	130	B8	130	Central	Note 1
BRONTE TS DESN 1	T6	54	B7	130	B8	130	Central	Note 1
BRONTE TS DESN 2	T2	54	B7	130	B8	130	Central	Note 1
BROWN HILL TS	Total	84	B82V	260	B83V	260	Central	Note 1
BUCHANAN TS	Total	42	W42L	240	W43L	240	West of London	150
BUCHANAN TS	B	12	W42L	240	W43L	240	West of London	150
BUCHANAN TS	Y	30	W42L	240	W43L	240	West of London	150
BUNTING TS	Total	2	Q11S	0	Q12S	0	Central	Note 1
BUNTING TS	J	0	Q11S	0	Q12S	0	Central	Note 1
BUNTING TS	Q	5	Q11S	0	Q12S	0	Central	Note 1
BURLEIGH DS	Total	2	F1B	60			Northwest	100
BURLINGTON TS	Total	107	Q23BM	40	Q25BM	60	Central	Note 1
BURLINGTON TS	BY	53	Q23BM	40	Q25BM	60	Central	Note 1
BURLINGTON TS	QJ	54	Q23BM	40	Q25BM	60	Central	Note 1
BUTTONVILLE TS	Total	21	P45	50	P46	50	Central	Note 1
BUTTONVILLE TS	Q	11	P45	50	P46	50	Central	Note 1
BUTTONVILLE TS	Z	10	P45	50	P46	50	Central	Note 1
CALEDONIA TS	Total	20	N1M	340	N5M	110	Central	Note 1
CALSTOCK DS	Total	5	H2N	0			Northeast	300
CAMBRIDGE NDUM MTS#1		Note 3	M20D	310	M21D	110	Central	Note 1
CAMPBELL TS - DESN 1	Total	11	D6V	240	D7V	240	Central	Note 1
CAMPBELL TS - DESN 1	BY	5	D6V	240	D7V	240	Central	Note 1
CAMPBELL TS - DESN 1	QJ	5	D6V	240	D7V	240	Central	Note 1
CAMPBELL TS DESN 2	Total	31	D6V	240	D7V	240	Central	Note 1
CARDIFF TS	Total	73	V41H	50	V42H	50	Central	Note 1
CARLAW TS	Total	5	H1L	10	H3L	50	Central	Note 1
CARLAW TS	A1A2	5	H1L	10	H3L	50	Central	Note 1
CARLAW TS	A6A7	5	H1L	10	H3L	50	Central	Note 1
CARLING TS	Total	26	M4G	100	M5G	100	East	1500
CARLING TS	KY	14	M4G	100	M5G	100	East	1500
CARLING TS	QZ	13	M4G	100	M5G	100	East	1500
CARLTON TS DESN 1	T1T4	18	D10S	0	D9HS	0	Central	Note 1
CARLTON TS DESN 2	BY	0	D10S	0	D9HS	0	Central	Note 1
CARLTON TS DESN 2	KH	5	D10S	0	D9HS	0	Central	Note 1
CARLTON TS DESN 2	T2T3	5	D10S	0	D9HS	0	Central	Note 1
CAT LAKE MTS		Note 3	E1C	20			Northwest	100
CAVANAGH MTS		Note 3	C10A	50	C20R	50	Central	Note 1
CECIL TS DESN 1	Total	5	H6LC	10	H8LC	10	Central	Note 1
CECIL TS DESN 1	A1A2	0	H6LC	10	H8LC	10	Central	Note 1
CECIL TS DESN 1	A3A4	5	H6LC	10	H8LC	10	Central	Note 1
CECIL TS DESN 2	Total	36	H6LC	10	H8LC	10	Central	Note 1
CECIL TS DESN 2	A5A6	14	H6LC	10	H8LC	10	Central	Note 1
CECIL TS DESN 2	A7A8	22	H6LC	10	H8LC	10	Central	Note 1
CEDAR TS DESN 1	Total	5	F11C	130	F12C	140	Central	Note 1
CEDAR TS DESN 1	YB	5	F11C	130	F12C	140	Central	Note 1
CEDAR TS DESN 1	ZE	0	F11C	130	F12C	140	Central	Note 1
CEDAR TS DESN 2	QJ	35	B5G	50	B6G	90	Central	Note 1
CENTRALIA TS	Total	30	L7S	30			Bruce	0
CENTRE POINT MTS		Note 3	C7BM	0			East	1500
CHAPLEAU DS	Total	0	W2C	40			Northeast	300
CHAPLEAU MTS		Note 3	W2C	40			Northeast	300
CHARLES TS DESN 1	Total	25	L4C	100	L9C	10	Central	Note 1
CHARLES TS DESN 1	A5A6	14	L4C	100	L9C	10	Central	Note 1
CHARLES TS DESN 1	A7A8	11	L4C	100	L9C	10	Central	Note 1
CHARLES TS DESN 2	Total	11	L12C	10	L4C	100	Central	Note 1
CHARLES TS DESN 2	A1A2	5	L12C	10	L4C	100	Central	Note 1
CHARLES TS DESN 2	A3A4	5	L12C	10	L4C	100	Central	Note 1
CHERRYWOOD TS	Total	82	Not expected to be limited by a supply circuit				Central	Note 1
CHESTERVILLE TS	Total	33	L2M	30			East	1500
CLARABELLE TS	Total	81	S22A	50	X23N	300	Northeast	300
CLARENCE DS	Total	2	79M1	50			East	1500
CLARKE TS	Total	74	W36	200	W37	200	West of London	150
CLEARWATER BAY DS	Total	4	SK1	70			Northwest	100
CLERGUE TS	Total	0	Clergue 1	0	Clergue 2	0	Northeast	300
COBDEN DS	Total	8	X2Y	40			East	1500
COBDEN TS	Total	1	X2Y	40	X6	40	East	1500
COBDEN TS	T1	0	X2Y	40	X6	40	East	1500
COBDEN TS	T2	13	X2Y	40	X6	40	East	1500
COCHRANE MTS		Note 3	A4H	0			Northeast	300
COCHRANE WEST DS	Total	4	A4H	0			Northeast	300
CONISTON TS	Total	0	L1S	50			Northeast	300
CONSTANCE DS	Total	18	M18	0			Bruce	0
CONSTANCE DS	T1	14	M19	0			Bruce	0
CONSTANCE DS	T2	16	M20	30			Bruce	0
COOKSVILLE TS DESN 1	JQ	58	K21C	50	K23C	50	Central	Note 1
COOKSVILLE TS DESN 2	BY	60	K21C	50	K23C	50	Central	Note 1
CRAIG DS	Total	10	D6	50			East	1500
CRAWFORD TS	Total	64	J3E	0	J4E	0	West of London	150

Station Name	Bus Name	Available Station Capacity (MW)	Supply Circuit 1	Availability (MW)	Supply Circuit 2	Availability (MW)	Area	Area Limit (MW)
CROSBY TS DESN 1	Total	23	L20H	100	L21H	100	East	1500
CROSBY TS DESN 1	T1	22	L20H	100	L21H	100	East	1500
CROSBY TS DESN 1	T2	22	L20H	100	L21H	100	East	1500
CROSBY TS DESN 2	Total	47	L20H	100	L21H	100	East	1500
CROW RIVER DS	Total	5	E1C	20			Northwest	100
CROW RIVER DS	T3	4	E1C	20			Northwest	100
CROW RIVER DS	T4	5	E1C	20			Northwest	100
CROWLAND TS	Total	61	A6C	110	A7C	100	Central	Note 1
CRYSTAL FALLS TS	Total	19	H23S	50	H24S	100	Northeast	300
CUMBERLAND DS	Total	5	H9A	50			East	1500
CUMBERLAND DS	T1	4	H9A	50			East	1500
CUMBERLAND DS	T2	3	H9A	50			East	1500
CUMBERLAND TS	Total	11	B40C	200	B41C	200	Central	Note 1
CUMBERLAND TS	B	5	B40C	200	B41C	200	Central	Note 1
CUMBERLAND TS	Q	5	B40C	200	B41C	200	Central	Note 1
D.A. WATSON TS	Total	0	High Falls 1	0	High Falls 2	20	Northeast	300
DEEP RIVER DS	Total	13	D6	50			Central	Note 1
DEEP RIVER DS	T1	5	D6	50			Central	Note 1
DEEP RIVER DS	T2	6	D6	50			Central	Note 1
DEEP RIVER DS	T3	6	D6	50			Central	Note 1
DES JOACHIMS DS		Note 3	D6	50			Central	Note 1
DETWEILER TS	Total	15	Not expected to be limited by a supply circuit				Central	Note 1
DOBBIN DS	Total	15	P3S	50			East	1500
DOBBIN DS	T1	14	P3S	50			East	1500
DOBBIN DS	T2	13	P3S	50			East	1500
DOBBIN TS	Total	72	Not expected to be limited by a supply circuit				East	1500
DOUGLAS POINT TS	Total	22	B20P	100	B24P	100	Bruce	0
DRYDEN TS	Total	21	Not expected to be limited by a supply circuit				Northwest	100
DUFFERIN TS DESN 1	Total	9	L13W	10	L15W	10	Central	Note 1
DUFFERIN TS DESN 1	A1A2	5	L13W	10	L15W	10	Central	Note 1
DUFFERIN TS DESN 1	A3A4	3	L13W	10	L15W	10	Central	Note 1
DUFFERIN TS DESN 2	Total	8	L13W	10	L15W	10	Central	Note 1
DUFFERIN TS DESN 2	A5A6	5	L13W	10	L15W	10	Central	Note 1
DUFFERIN TS DESN 2	A7A8	2	L13W	10	L15W	10	Central	Note 1
DUNDAS TS	Total	72	B3	90	B4	90	Central	Note 1
DUNDAS TS #2	Total	53	B12	110	B13	110	Central	Note 1
DUNNVILLE TS	Total	0	Q2A	90			Central	Note 1
DUPLEX TS DESN 1	Total	11	D6Y	240	L16D	10	Central	Note 1
DUPLEX TS DESN 1	A1A2	5	D6Y	240	L16D	10	Central	Note 1
DUPLEX TS DESN 1	A3A4	5	D6Y	240	L16D	10	Central	Note 1
DUPLEX TS DESN 2	A5A6	1	D6Y	240	L16D	10	Central	Note 1
DYMOND TS	Total	19	W71D	150			Northeast	300
EAR FALLS TS	Total	11	Not expected to be limited by a supply circuit				Northwest	100
ECHO RIVER TS	Total	18	P22G	40			Northeast	300
EDGEWARE TS	Total	6	W44LC	300	W45LC	380	West of London	150
EDGEWARE TS	B	8	W44LC	300	W45LC	380	West of London	150
EDGEWARE TS	Y	0	W44LC	300	W45LC	380	West of London	150
ELGIN TS DESN 1	Total	7	HL3	130	HL4	130	Central	Note 1
ELGIN TS DESN 1	DK	5	HL3	130	HL4	130	Central	Note 1
ELGIN TS DESN 1	JQ	2	HL3	130	HL4	130	Central	Note 1
ELGIN TS DESN 2	Total	25	HL3	130	HL4	130	Central	Note 1
ELLESMERE TS	Total	22	C2L	50	C3L	50	Central	Note 1
ELLESMERE TS	J	11	C2L	50	C3L	50	Central	Note 1
ELLESMERE TS	Q	11	C2L	50	C3L	50	Central	Note 1
ELLIOT LAKE TS	Total	26	B3E	90	B4E	120	Northeast	300
ELMIRA TS	Total	13	D10H	70			Central	Note 1
ERINDALE TS DESN 1	Total	16	R19T	0	R21T	0	Central	Note 1
ERINDALE TS DESN 1	E	11	R19T	0	R21T	0	Central	Note 1
ERINDALE TS DESN 1	Q	5	R19T	0	R21T	0	Central	Note 1
ERINDALE TS DESN 2	YZ T3T4	95	R14T	0	R17T	0	Central	Note 1
ERINDALE TS DESN 3	BJ T5T6	104	R19T	0	R21T	0	Central	Note 1
ESPANOLA TS	Total	19	S2B	50			Northeast	300
ESPLANADE TS	Total	58	H2JK	10	H9EJ	10	Central	Note 1
ESPLANADE TS	A1A2	17	H2JK	10	H9EJ	10	Central	Note 1
ESPLANADE TS	J1J2	23	H2JK	10	H9EJ	10	Central	Note 1
ESPLANADE TS	Q1Q2	17	H2JK	10	H9EJ	10	Central	Note 1
ESSEX TS	Total	54	Not expected to be limited by a supply circuit				West of London	150
ETON DS	Total	8	K3D	0			Northwest	100
EVERETT TS	Total	63	E8V	140	E9V	140	Central	Note 1
FAIRBANK TS DESN 1	YZ	65	K1W	10	K3W	10	Central	Note 1
FAIRBANK TS DESN 2	BQ	59	K1W	10	K3W	10	Central	Note 1
FAIRCHILD TS DESN 1	B	11	C18R	50	C20R	50	Central	Note 1
FAIRCHILD TS DESN 1	BY	22	C18R	50	C20R	50	Central	Note 1
FAIRCHILD TS DESN 1	Y	11	C18R	50	C20R	50	Central	Note 1
FAIRCHILD TS DESN 2	J	5	C18R	50	C20R	50	Central	Note 1
FAIRCHILD TS DESN 2	Q	11	C18R	50	C20R	50	Central	Note 1
FAIRCHILD TS DESN 2	QJ	15	C18R	50	C20R	50	Central	Note 1
FALLOWFIELD DS		Note 3	S7M	0			East	1500

Station Name	Bus Name	Available Station Capacity (MW)	Supply Circuit 1	Availability (MW)	Supply Circuit 2	Availability (MW)	Area	Area Limit (MW)
FAUQUIER DS	Total	2	H9K	0			Northeast	300
FERGUS TS	Total	79	D6V	240	D7V	240	Central	Note 1
FINCH TS DESN 1	B	11	C20R	50	P22R	50	Central	Note 1
FINCH TS DESN 1	T1T2	22	C20R	50	P22R	50	Central	Note 1
FINCH TS DESN 1	Y	11	C20R	50	P22R	50	Central	Note 1
FINCH TS DESN 2	J	11	C4R	50	P21R	50	Central	Note 1
FINCH TS DESN 2	Q	11	C4R	50	P21R	50	Central	Note 1
FINCH TS DESN 2	T3T4	22	C4R	50	P21R	50	Central	Note 1
FOREST JURA DS	Total	1	S2N	0			West of London	150
FOREST JURA DS	T1	16	S2N	0			West of London	150
FOREST JURA DS	T2	0	S2N	0			West of London	150
FOREST LEA DS	Total	8	D6	50			Central	Note 1
FOREST LEA DS	T1	7	D6	50			Central	Note 1
FOREST LEA DS	T2	6	D6	50			Central	Note 1
FORT FRANCES MTS		Note 3	F1B	60			Northwest	100
FORT FRANCES TS	T3	54	K24F	50	F25A	50	Northwest	100
FORT WILLIAM TS	Total	20	Q4B	100	Q5B	100	Northwest	100
FRONTENAC TS	Total	67	B5QK	40	Q3K	110	East	1500
GALT TS	Total	22	M20D	310	M21D	110	Central	Note 1
GALT TS	J	11	M20D	310	M21D	110	Central	Note 1
GALT TS	Y	11	M20D	310	M21D	110	Central	Note 1
GERRARD TS DESN 1	A1A2	20	H1L	10	H3L	50	Central	Note 1
GERRARD TS DESN 2	A7A9	25	H1L	10	H3L	50	Central	Note 1
GLENDALE TS	BJ	3	Q11S	0	Q12S	0	Central	Note 1
GLENDALE TS	DQ	1	Q11S	0	Q12S	0	Central	Note 1
GLENDALE TS	T1T2	4	Q11S	0	Q12S	0	Central	Note 1
GLENDALE TS DESN 2	EY T3T4	0	D9HS	0	D10S	0	Central	Note 1
GLENGROVE TS DESN 1	A1A2	25	D6Y	240	L2Y	30	Central	Note 1
GLENGROVE TS DESN 2	A5A6	24	D6Y	240	L2Y	30	Central	Note 1
GODERICH TS	Total	0	61M18	50			Bruce	0
GOREWAY TS DESN 2	T4	0	V42H	50	V43	50	Central	Note 1
GOREWAY TS DESN1	B	11	V42H	50	V43	50	Central	Note 1
GOREWAY TS DESN1	BY	22	V42H	50	V43	50	Central	Note 1
GOREWAY TS DESN1	Y	11	V42H	50	V43	50	Central	Note 1
GOULAIS BAY TS	Total	0	Sault 3	0			Northeast	300
GRAND BEND EAST DS	Total	17	L7S	30			Bruce	0
GRAND BEND EAST DS	T1	15	L7S	30			Bruce	0
GRAND BEND EAST DS	T2	15	L7S	30			Bruce	0
GREELY DS	Total	21	M1R	40			East	1500
GREELY DS	T1	18	M1R	40			East	1500
GREELY DS	T2	19	M1R	40			East	1500
HALTON TS	Total	103	T38B	50	T39B	50	Central	Note 1
HALTON TS	J	51	T38B	50	T39B	50	Central	Note 1
HALTON TS	Q	51	T38B	50	T39B	50	Central	Note 1
HAMILTON GAGE TS DESN 1	Total	0	K1G	10	K2G	40	Central	Note 1
HAMILTON GAGE TS DESN 1	T1	0	K1G	10	K2G	40	Central	Note 1
HAMILTON GAGE TS DESN 1	T2	0	K1G	10	K2G	40	Central	Note 1
HAMILTON GAGE TS DESN 1	T7	0	K1G	10	K2G	40	Central	Note 1
HAMILTON GAGE TS DESN 2	T3T4	0	B10	190	B11	190	Central	Note 1
HAMILTON GAGE TS DESN 3	T5T6	0	B10	190	B11	190	Central	Note 1
HAMILTON GAGE TS DESN 4	T8T9	81	B10	190	B11	190	Central	Note 1
HANLON TS	Total	30	B5G	50	B6G	90	Central	Note 1
HANOVER TS	Total	70	B4V	0	B5V	0	Bruce	0
HARROWSMITH DS	Total	10	B5QK	40			East	1500
HARROWSMITH DS	T1	8	B5QK	40			East	1500
HARROWSMITH DS	T2	8	B5QK	40			East	1500
HAVELOCK TS	Total	32	H24C	50	H27H	250	East	1500
HAWKESBURY MTS #1		Note 3	79M1	50			East	1500
HAWTHORNE TS	Total	79	Not expected to be limited by a supply circuit				East	1500
HEARST TS	Total	25	F1E	0			Northeast	300
HERRIDGE LAKE DS	Total	2	D2L	50			Northeast	300
HIGHBURY TS	Total	70	W6NL	140	W9L	140	West of London	150
HINCHEY TS	Total	0	F10MV	110	V12M	110	East	1500
HINCHINBROOKE DS	Total	5	B5QK	40			East	1500
HOLLINGSWORTH TS	Total	0	Hollingsworth	40	R2K	50	Northeast	300
HORNER TS	Total	97	R15K	0	R2K	50	Central	Note 1
HORNER TS	B	49	R15K	0	R2K	50	Central	Note 1
HORNER TS	Y	48	R15K	0	R2K	50	Central	Note 1
HORNING TS	Total	68	M27B	230	M28B	230	Central	Note 1
HORNING TS	B	34	M27B	230	M28B	230	Central	Note 1
HORNING TS	Q	34	M27B	230	M28B	230	Central	Note 1
HOYLE DS	Total	13	P7G	130			Northeast	300
INGERSOLL TS	Total	22	M32W	110	M33W	380	West of London	150
INGERSOLL TS	E	11	M32W	110	M33W	380	West of London	150
INGERSOLL TS	Z	11	M32W	110	M33W	380	West of London	150
IROQUOIS FALLS DS	Total	6	A5H	0			Northeast	300
JARVIS TS	Total	47	N21J	430	N22J	430	Central	Note 1
JELLICOE DS	Total	1	A4L	0			Northwest	100

Station Name	Bus Name	Available Station Capacity (MW)	Supply Circuit 1	Availability (MW)	Supply Circuit 2	Availability (MW)	Area	Area Limit (MW)
JIM YARROW MTS		Note 3	R19T	0	R21T	0	Central	Note 1
JOHN TS DESN 1	A17A18	Note 3	Not expected to be limited by a supply circuit				Central	Note 1
JOHN TS DESN 1	A4A6	Note 3	Not expected to be limited by a supply circuit				Central	Note 1
JOHN TS DESN 2	A13A14	Note 3	Not expected to be limited by a supply circuit				Central	Note 1
JOHN TS DESN 2	A3A5	Note 3	Not expected to be limited by a supply circuit				Central	Note 1
JOHN TS DESN 3	A11A12	Note 3	Not expected to be limited by a supply circuit				Central	Note 1
JOHN TS DESN 3	A15A16	Note 3	Not expected to be limited by a supply circuit				Central	Note 1
KALAR MTS		Note 3	A36N	120	A37N	120	Central	Note 1
KANATA MTS #1		Note 3	C3S	350	M32S	300	East	1500
KAPUSKASING TS	Total	27	K38S	0			Northeast	300
KEITH TS DESN 1	BY	14	Not expected to be limited by a supply circuit				West of London	150
KEITH TS DESN 2	T1	0	Not expected to be limited by a supply circuit				West of London	150
KENORA DS	Total	8	Not expected to be limited by a supply circuit				Northwest	100
KENORA MTS		Note 3	15M1	100			Northwest	100
KENT TS DESN1	B T1T2	0	L28C	- (Note 2)	L29C	- (Note 2)	West of London	150
KENT TS DESN1	BY	104	L28C	- (Note 2)	L29C	- (Note 2)	West of London	150
KENT TS DESN1	Y T1T2	4	L28C	- (Note 2)	L29C	- (Note 2)	West of London	150
KENT TS DESN2	E T4	29	L28C	- (Note 2)	L29C	- (Note 2)	West of London	150
KING EDWARD TS	Total	6	A4K	50	A5RK	50	East	1500
KING EDWARD TS	JY T3T4	3	A4K	50	A5RK	50	East	1500
KING EDWARD TS	QZ T3T4	3	A4K	50	A5RK	50	East	1500
KINGSTON GARDINER TS	Total	126	X2H	350	X4H	350	East	1500
KINGSVILLE TS	Total	8	K2Z	- (Note 2)	K6Z	- (Note 2)	West of London	150
KIRKLAND LAKE TS	Total	19	Not expected to be limited by a supply circuit				Northeast	300
KITCHENER MTS#1		Note 3	D11K	110	D12K	110	Central	Note 1
KITCHENER MTS#3		Note 3	D7F	10	D9F	50	Central	Note 1
KITCHENER MTS#4		Note 3	D11K	110	D12K	110	Central	Note 1
KITCHENER MTS#5		Note 3	F11C	130	F12C	140	Central	Note 1
KITCHENER MTS#6		Note 3	M20D	310	M21D	110	Central	Note 1
KITCHENER MTS#7		Note 3	D7F	10	D9F	50	Central	Note 1
KLEINBURG TS 27.6 KV	BY T1T2	10	V43	50	V44	50	Central	Note 1
KLEINBURG TS 44 KV	JQ T1T2	18	V43	50	V44	50	Central	Note 1
LAFOREST ROAD DS	Total	20	H6T	0			Northeast	300
LAKE TS DESN 1	Total	Note 3	B18H	190	B20H	280	Central	Note 1
LAKE TS DESN 2	Total	11	B18H	190	B20H	280	Central	Note 1
LAKE TS DESN 2	J1J2	5	B18H	190	B20H	280	Central	Note 1
LAKE TS DESN 2	Q1Q2	5	B18H	190	B20H	280	Central	Note 1
LAMBTON TS	Total	40	Not expected to be limited by a supply circuit				West of London	150
LAMBTON TS	D T5	20	Not expected to be limited by a supply circuit				West of London	150
LAMBTON TS	Y T6	20	Not expected to be limited by a supply circuit				West of London	150
LARCHWOOD TS	Total	14	S5M	40			Northeast	300
LAUZON TS DESN1	QB	65	C23Z	- (Note 2)	C24Z	- (Note 2)	West of London	150
LAUZON TS DESN2	EJ	33	C23Z	- (Note 2)	C24Z	- (Note 2)	West of London	150
LEASIDE TS DESN 1	A1A2Q1Q2	5	C2L	50	C3L	50	Central	Note 1
LEASIDE TS DESN 2	BY	5	C2L	50	C3L	50	Central	Note 1
LESLIE TS DESN	Total	0	C5R	50	P21R	50	Central	Note 1
LESLIE TS DESN	H1	0	C5R	50	P21R	50	Central	Note 1
LESLIE TS DESN	H2	0	C5R	50	P21R	50	Central	Note 1
LESLIE TS DESN 1	Total	1	C5R	50	P21R	50	Central	Note 1
LESLIE TS DESN 1	BY	1	C5R	50	P21R	50	Central	Note 1
LESLIE TS DESN 2	Total	22	C5R	50	P21R	50	Central	Note 1
LESLIE TS DESN 2	J	11	C5R	50	P21R	50	Central	Note 1
LESLIE TS DESN 2	Q	11	C5R	50	P21R	50	Central	Note 1
LIMEBANK MTS		Note 3	L2M	30			East	1500
LINCOLN HEIGHTS TS	Total	0	C7BM	0	F10MV	110	East	1500
LINCOLN HEIGHTS TS	B	0	C7BM	0	F10MV	110	East	1500
LINCOLN HEIGHTS TS	Y	0	C7BM	0	F10MV	110	East	1500
LINDSAY TS	Total	75	M80B	70	M81B	70	Central	Note 1
LINDSAY TS	T1	62	M80B	70	M81B	70	Central	Note 1
LINDSAY TS	T2	75	M80B	70	M81B	70	Central	Note 1
LISGAR TS	Total	5	M4G	100	M5G	100	East	1500
LISGAR TS	JY	0	M4G	100	M5G	100	East	1500
LISGAR TS	QZ	5	M4G	100	M5G	100	East	1500
LODGEROOM DS	Total	8	B1S	0			East	1500
LODGEROOM DS	T1	8	B1S	0			East	1500
LODGEROOM DS	T2	7	B1S	0			East	1500
LONGLAC TS	Total	4	A4L	0			Northwest	100
LONGUEUIL TS	Total	32	B5D	0	D5A	50	East	1500
LONGWOOD TS	Total	49	L24L	110	L26L	110	Bruce	0
LORNE PARK TS	Total	22	B15C	0	B16C	0	Central	Note 1
LORNE PARK TS	B	11	B15C	0	B16C	0	Central	Note 1
LORNE PARK TS	J	11	B15C	0	B16C	0	Central	Note 1
MALVERN TS	Total	21	C4R	50	C5R	50	Central	Note 1
MALVERN TS	J	11	C4R	50	C5R	50	Central	Note 1
MALVERN TS	Q	10	C4R	50	C5R	50	Central	Note 1
MANBY TS DESN 1	BY	35	R2K	50	R15K	0	Central	Note 1
MANBY TS DESN 2	QZ	37	R1K	0	R13K	0	Central	Note 1
MANBY TS DESN 3	VF	78	R2K	50	R15K	0	Central	Note 1

Station Name	Bus Name	Available Station Capacity (MW)	Supply Circuit 1	Availability (MW)	Supply Circuit 2	Availability (MW)	Area	Area Limit (MW)
MANITOULIN TS	Total	21	S2B	50			Northeast	300
MANITOULIN TS	T3	17	S2B	50			Northeast	300
MANITOULIN TS	T4	26	S2B	50			Northeast	300
MANITOUWADGE DS	Total	3	M2W	20			Northwest	100
MANITOUWADGE TS	Total	11	M2W	20			Northwest	100
MANORDALE MTS		Note 3	S7M	0			East	1500
MANOTICK DS	Total	7	T1M	0			East	1500
MANOTICK DS	T1	8	T1M	0			East	1500
MANOTICK DS	T2	5	T1M	0			East	1500
MARATHON DS	Total	4	K6F	0			Northwest	100
MARCHWOOD MTS		Note 3	S7M	0			East	1500
MARGACH DS	Total	6	K6F	0			Northwest	100
MARGACH DS	T1	6	K6F	0			Northwest	100
MARGACH DS	T2	6	K6F	0			Northwest	100
MARIONVILLE DS	Total	16	L2M	30			East	1500
MARKHAM MTS #1		Note 3	P21R	50	P22R	50	Central	Note 1
MARKHAM MTS #3		Note 3	C35P	50	C36P	50	Central	Note 1
MARTINDALE TS	Total	67	Not expected to be limited by a supply circuit				Northeast	300
MASSEY DS	Total	4	S2B	50			Northeast	300
MAZINAW DS	Total	4	X1P	0			East	1500
MEADOWVALE TS	Total	132	T38B	50	T39B	50	Central	Note 1
MEAFORD TS	Total	2	S2S	0			Central	Note 1
MERIVALE MTS		Note 3	A3RM	50	A8M	90	East	1500
MIDHURST TS	Total	121	M6E	70	M7E	70	Central	Note 1
MINAKI DS	Total	6	K4W	20			Northwest	100
MINAKI DS	T1	6	K4W	20			Northwest	100
MINAKI DS	T2	6	K4W	20			Northwest	100
MINDEN TS	Total	31	Not expected to be limited by a supply circuit				Central	Note 1
MINDEN TS	T1	15	Not expected to be limited by a supply circuit				Central	Note 1
MINDEN TS	T2	29	Not expected to be limited by a supply circuit				Central	Note 1
MODELAND TS	Total	0	N21W	80	N22W	70	West of London	150
MODELAND TS	J	0	N21W	80	N22W	70	West of London	150
MODELAND TS	Q	10	N21W	80	N22W	70	West of London	150
MOHAWK TS	Total	10	B3	90	B4	90	Central	Note 1
MOHAWK TS	B	5	B3	90	B4	90	Central	Note 1
MOHAWK TS	Y	5	B3	90	B4	90	Central	Note 1
MONTEITH DS	Total	7	A9K	0			Northeast	300
MOOSE LAKE TS	Total	0	Not expected to be limited by a supply circuit				Northwest	100
MOOSE LAKE TS	T2	5	Not expected to be limited by a supply circuit				Northwest	100
MOOSE LAKE TS	T3	0	Not expected to be limited by a supply circuit				Northwest	100
MOOSONEE DS	Total	11	M9K	40			Northeast	300
MORRISBURG TS	Total	50	L1MB	50	L2M	30	East	1500
MOULTON MTS		Note 3	Not expected to be limited by a supply circuit				East	1500
MOUNTAIN CHUTE DS	Total	2	W3B	0			East	1500
MURILLO DS	Total	0	B6M	0			Northwest	100
MURRAY TS DESN 1	Total	11	A36N	120	A37N	120	Central	Note 1
MURRAY TS DESN 1	QZ	5	A36N	120	A37N	120	Central	Note 1
MURRAY TS DESN 1	Y1Y2	5	A36N	120	A37N	120	Central	Note 1
MURRAY TS DESN 2	Total	6	A36N	120	A37N	120	Central	Note 1
MURRAY TS DESN 2	J	0	A36N	120	A37N	120	Central	Note 1
MURRAY TS DESN 2	K	5	A36N	120	A37N	120	Central	Note 1
MUSKOKA TS	Total	74	M6E	70	M7E	70	Central	Note 1
N.O.T.L. MTS #2		Note 3	Q11S	0			Central	Note 1
N.O.T.L. YORK MTS		Note 3	Q12S	0			Central	Note 1
NAPANEE TS	Total	19	X21	200	X22	270	East	1500
NAPANEE TS	B T1	34	X21	200	X22	270	East	1500
NAPANEE TS	Y T2	26	X21	200	X22	270	East	1500
NAVAN DS	Total	4	H9A	50			East	1500
NEBO TS DESN 1	BY	61	Q24HM	10	Q29HM	50	Central	Note 1
NEBO TS DESN2	TS	5	Q24HM	10	Q29HM	50	Central	Note 1
NELSON TS DESN 1	BQ	24	W5N	140	W6NL	140	West of London	150
NELSON TS DESN 2	Total	11	W5N	140	W6NL	140	West of London	150
NELSON TS DESN 2	PK	5	W5N	140	W6NL	140	West of London	150
NELSON TS DESN 2	YJ	5	W5N	140	W6NL	140	West of London	150
NEPEAN EPWORTH MTS		Note 3	M4G	100	M5G	100	East	1500
NEPEAN TS	Total	105	M32S	300			East	1500
NESTOR FALLS DS	Total	2	K6F	0			Northwest	100
NEWINGTON DS	Total	8	L2M	30			East	1500
NEWTON TS	Total	11	B3	90	B4	90	Central	Note 1
NEWTON TS	B	5	B3	90	B4	90	Central	Note 1
NEWTON TS	Y	5	B3	90	B4	90	Central	Note 1
NIAGARA WEST MTS		Note 3	Q23BM	40	Q25BM	60	Central	Note 1
NIPIGON DS	Total	2	57M1	0			Northwest	100
NORFOLK TS	Total	37	C12	120	C9	120	Central	Note 1
NORTH BAY TS	Total	15	L5H	50			Northeast	300
NORTH SHORE DS	Total	1	T1B	0			Northeast	300
NORTHBROOK DS	Total	8	B1S	0			East	1500
NORTHERN AVE. TS	Total	18	Northern Ave	0			Northeast	300

Station Name	Bus Name	Available Station Capacity (MW)	Supply Circuit 1	Availability (MW)	Supply Circuit 2	Availability (MW)	Area	Area Limit (MW)
OAKVILLE TS	Total	22	B15C	0	B16C	0	Central	Note 1
OAKVILLE TS	E	11	B15C	0	B16C	0	Central	Note 1
OAKVILLE TS	Z	11	B15C	0	B16C	0	Central	Note 1
ORANGEVILLE TS 27 KV - DESN1	Total	53	Not expected to be limited by a supply circuit				Central	Note 1
ORANGEVILLE TS 44 KV - DESN1	Total	24	Not expected to be limited by a supply circuit				Central	Note 1
ORANGEVILLE TS DESN2	Total	13	Not expected to be limited by a supply circuit				Central	Note 1
ORILLIA TS	Total	91	M6E	70	M7E	70	Central	Note 1
OSHAWA G.M. TS		Note 3	H24C	50	H26C	50	East	1500
OTONABEE TS DESN 1	Total	13	C28C	200	H24C	50	East	1500
OTONABEE TS DESN 1	J	5	C28C	200	H24C	50	East	1500
OTONABEE TS DESN 1	Q	8	C28C	200	H24C	50	East	1500
OTONABEE TS DESN 2	Total	12	C28C	200	H24C	50	East	1500
OTONABEE TS DESN 2	B	6	C28C	200	H24C	50	East	1500
OTONABEE TS DESN 2	Y	6	C28C	200	H24C	50	East	1500
OVERBROOK TS	Total	8	A4K	50	A5RK	50	East	1500
OVERBROOK TS	J	3	A4K	50	A5RK	50	East	1500
OVERBROOK TS	Q	5	A4K	50	A5RK	50	East	1500
OWEN SOUND TS	Total	102	B27S	0	B28S	0	Bruce	0
PALERMO TS	Total	66	T36B	50	T37B	50	Central	Note 1
PALMERSTON TS	Total	57	D10H	70			Bruce	0
PARRY SOUND TS	Total	0	E26	210	E27	210	Central	Note 1
PEMBROKE TS	Total	16	X6	40	X2Y	40	East	1500
PERRAULT FALLS DS	Total	1	E4D	40			Northwest	100
PETAWAWA DS	Total	6	D6	50			Central	Note 1
PETAWAWA DS	T1	5	D6	50			Central	Note 1
PETAWAWA DS	T2	4	D6	50			Central	Note 1
PIC DS	Total	0	M2W	20			Northwest	100
PICTON TS	Total	31	X21	200	X22	270	East	1500
PLEASANT TS DESN 2	Total	99	R19T	0	R21T	0	Central	Note 1
PLEASANT TS DESN 2	BY	42	R19T	0	R21T	0	Central	Note 1
PLEASANT TS DESN 2	EZ	57	R19T	0	R21T	0	Central	Note 1
PLEASANT TS DESN 3	Total	5	R19T	0	R21T	0	Central	Note 1
PLEASANT TS DESN 3	F	2	R19T	0	R21T	0	Central	Note 1
PLEASANT TS DESN 3	V	3	R19T	0	R21T	0	Central	Note 1
PLEASANT TS DESN1	Total	101	R19T	0	R21T	0	Central	Note 1
PORT ARTHUR TS	Total	10	Not expected to be limited by a supply circuit				Northwest	100
PORT COLBORNE TS	Total	24	C2P	70			Central	Note 1
PORT HOPE TS DESN 1	Total	51	P3S	50	P4S	70	East	1500
PORT HOPE TS DESN 2	Total	70	P3S	50	P4S	70	East	1500
POWERLINE MTS		Note 3	B12	110	B13	110	Central	Note 1
PRESTON TS	Total	19	M20D	310	M21D	110	Central	Note 1
PRESTON TS	J	10	M20D	310	M21D	110	Central	Note 1
PRESTON TS	Q	9	M20D	310	M21D	110	Central	Note 1
PUSLINCH DS	Total	21	B5G	50	B6G	90	Central	Note 1
PUSLINCH DS	T1	15	B5G	50	B6G	90	Central	Note 1
PUSLINCH DS	T2	16	B5G	50	B6G	90	Central	Note 1
RAMORE TS	Total	9	A9K	0			Northeast	300
RED LAKE TS	Total	40	E2R	50			Northwest	100
RED ROCK DS	Total	4	56M1	0			Northwest	100
REXDALE TS	Total	106	V74R	50	V76R	50	Central	Note 1
REXDALE TS	BY	56	V74R	50	V76R	50	Central	Note 1
REXDALE TS	QJ	50	V74R	50	V76R	50	Central	Note 1
RICHMOND DS		Note 3	S7M	0			East	1500
RICHMOND HILL MTS #1		Note 3	V71P	50	V75P	50	Central	Note 1
RICHMOND HILL MTS #2		Note 3	V71P	50	V75P	50	Central	Note 1
RICHVIEW TS DESN 1	E	11	Not expected to be limited by a supply circuit				Central	Note 1
RICHVIEW TS DESN 1	EJ	22	Not expected to be limited by a supply circuit				Central	Note 1
RICHVIEW TS DESN 1	J	11	Not expected to be limited by a supply circuit				Central	Note 1
RICHVIEW TS DESN 2	Total	97	Not expected to be limited by a supply circuit				Central	Note 1
RICHVIEW TS DESN 2	Q	50	Not expected to be limited by a supply circuit				Central	Note 1
RICHVIEW TS DESN 2	Z	47	Not expected to be limited by a supply circuit				Central	Note 1
RICHVIEW TS DESN 3	Total	64	Not expected to be limited by a supply circuit				Central	Note 1
RIVERDALE TS	Total	23	A3RM	50	A5RK	50	East	1500
RIVERDALE TS	JY	13	A3RM	50	A5RK	50	East	1500
RIVERDALE TS	QZ	11	A3RM	50	A5RK	50	East	1500
ROCKLAND DS	Total	8	79M1	50			East	1500
ROCKLAND EAST DS	Total	8	79M1	50			East	1500
ROCKLAND EAST DS	T1	6	79M2	50			East	1500
ROCKLAND EAST DS	T2	7	79M3	50			East	1500
RUNNYMEDE TS	Total	79	K11W	10	K12W	10	Central	Note 1
RUSH MTS		Note 3	D8S	70	D10H	70	Central	Note 1
RUSSELL DS	Total	2	M1R	40			East	1500
RUSSELL TS	Total	11	A5RK	50	A6R	50	East	1500
RUSSELL TS	BY	5	A5RK	50	A6R	50	East	1500
RUSSELL TS	QZ	5	A5RK	50	A6R	50	East	1500
SAM LAKE DS	Total	19	K3D	0			Northwest	100
SAPAWE DS	Total	2	B6M	0			Northwest	100
SCARBORO TS - DESN1	Total	22	C14L	50	C2L	50	Central	Note 1

Station Name	Bus Name	Available Station Capacity (MW)	Supply Circuit 1	Availability (MW)	Supply Circuit 2	Availability (MW)	Area	Area Limit (MW)
SCARBORO TS - DESN1	J	11	C14L	50	C2L	50	Central	Note 1
SCARBORO TS - DESN1	Q	11	C14L	50	C2L	50	Central	Note 1
SCARBORO TS - DESN2	Total	14	C15L	50	C3L	50	Central	Note 1
SCARBORO TS - DESN2	B	4	C15L	50	C3L	50	Central	Note 1
SCARBORO TS - DESN2	Y	11	C15L	50	C3L	50	Central	Note 1
SCHEIFELE MTS		Note 3	D6V	240	D7V	240	Central	Note 1
SCHREIBER WINNIPG DS	Total	4	A5A	0			Northwest	100
SEAFORTH TS	Total	33	B22D	0	B23D	0	Bruce	0
SHABAQUA DS	Total	4	B6M	0			Northwest	100
SHABAQUA DS	T2	1	B6M	0			Northwest	100
SHARBOT DS	Total	4	B5QK	40			East	1500
SHEPPARD TS DESN 1	T1T2	68	C15L	50	C16L	50	Central	Note 1
SHEPPARD TS DESN 2	T3T4	75	C15L	50	C16L	50	Central	Note 1
SHININGTREE DS	Total	2	T61S	20			Northeast	300
SIDNEY TS	Total	41	Not expected to be limited by a supply circuit				East	1500
SIOUX NARROWS DS	Total	1	K6F	0			Northwest	100
SLATE FALLS DS	Total	2	E1C	20			Northwest	100
SLATER TS	Total	16	A3RM	50	A5RK	50	East	1500
SLATER TS	B1B2	5	A3RM	50	A5RK	50	East	1500
SLATER TS	J1J2	5	A3RM	50	A5RK	50	East	1500
SLATER TS	Q1Q2	5	A3RM	50	A5RK	50	East	1500
SMITHS FALLS TS	Total	72	L21H	100	L22H	100	East	1500
SMOOTH ROCK FALLS DS	Total	7	H9K	0			Northeast	300
SMOOTH ROCK FALLS DS	T1	7	H9K	0			Northeast	300
SMOOTH ROCK FALLS DS	T2	6	H9K	0			Northeast	300
SOUTH GLOUCESTER DS	Total	4	M1R	40			East	1500
SOUTH MARCH TS	Total	71	C3S	350	M32S	300	East	1500
SOWERBY DS	Total	4	T1B	0			Northeast	300
SPANISH DS	Total	7	S2B	50			Northeast	300
ST ANDREWS TS	Total	57	N6C	110	N7C	100	West of London	150
ST ISIDORE TS	Total	15	B5D	0	D5A	50	East	1500
ST LAWRENCE TS	Total	74	Not expected to be limited by a supply circuit				East	1500
ST MARYS TS	Total	29	L7S	30			Bruce	0
ST THOMAS TS DESN 1	Total	11	T11T	100	W3T	60	West of London	150
ST THOMAS TS DESN 2	Total	22	T11T	100	W3T	60	West of London	150
STANLEY TS	Total	11	Q3L	130	Q4N	0	Central	Note 1
STANLEY TS	BY	5	Q3L	130	Q4N	0	Central	Note 1
STANLEY TS	QJ	5	Q3L	130	Q4N	0	Central	Note 1
STAYNER TS	Total	82	E20S	300	E21S	300	Central	Note 1
STEWARTVILLE TS	Total	22	W3B	0	W6CS	0	East	1500
STIRTON TS	Total	12	HL3	130	HL4	130	Central	Note 1
STIRTON TS	BY	11	HL3	130	HL4	130	Central	Note 1
STIRTON TS	QZ	1	HL3	130	HL4	130	Central	Note 1
STRACHAN TS DESN 1	Total	6	H2JK	10	K6J	10	Central	Note 1
STRACHAN TS DESN 1	A5A6	3	H2JK	10	K6J	10	Central	Note 1
STRACHAN TS DESN 1	A7A8	3	H2JK	10	K6J	10	Central	Note 1
STRACHAN TS DESN 2	Total	6	H2JK	10	K6J	10	Central	Note 1
STRACHAN TS DESN 2	A1A2	3	H2JK	10	K6J	10	Central	Note 1
STRACHAN TS DESN 2	A3A4	3	H2JK	10	K6J	10	Central	Note 1
STRATFORD TS	Total	78	B22D	0	B23D	0	Bruce	0
STRATHROY TS	Total	8	W2S	40			West of London	150
STRIKER DS	Total	8	T1B	0			Northeast	300
STRIKER DS	T1	11	T1B	0			Northeast	300
STRIKER DS	T2	8	T1B	0			Northeast	300
TALBOT TS DESN 1	T1T2	64	W36	200	W37	200	West of London	150
TALBOT TS DESN 2	Total	22	W36	200	W37	200	West of London	150
TALBOT TS DESN 2	J1J2	11	W36	200	W37	200	West of London	150
TALBOT TS DESN 2	Q1Q2	11	W36	200	W37	200	West of London	150
TEMAGAMI DS	Total	3	D2L	50			Northeast	300
TERAULEY TS DESN 1	Total	11	C5E	50	C7E	0	Central	Note 1
TERAULEY TS DESN 1	A1A2	5	C5E	50	C7E	0	Central	Note 1
TERAULEY TS DESN 1	A7A8	5	C5E	50	C7E	0	Central	Note 1
TERAULEY TS DESN 2	Total	11	C5E	50	C7E	0	Central	Note 1
TERAULEY TS DESN 2	A3A4	5	C5E	50	C7E	0	Central	Note 1
TERAULEY TS DESN 2	A5A6	5	C5E	50	C7E	0	Central	Note 1
THORNTON TS	Total	102	H24C	50	H26C	50	East	1500
THOROLD TS	Total	11	D1A	0	D3A	0	Central	Note 1
THOROLD TS	BY	5	D1A	0	D3A	0	Central	Note 1
THOROLD TS	EQ	5	D1A	0	D3A	0	Central	Note 1
TILBURY TS	Total	0	K2Z	- (Note 2)			West of London	150
TILBURY WEST DS	Total	0	K2Z	- (Note 2)			West of London	150
TILBURY WEST DS	T1	14	K2Z	- (Note 2)			West of London	150
TILBURY WEST DS	T2	0	K2Z	- (Note 2)			West of London	150
TILLSONBURG TS	Total	20	WT1T	0			West of London	150
TIMMINS TS	Total	61	Not expected to be limited by a supply circuit				Northeast	300
TOMKEN TS DESN1	Total	103	R14T	0	R17T	0	Central	Note 1
TOMKEN TS DESN2	Total	104	R19T	0	R21T	0	Central	Note 1
Toronto MAIN TS	Total	10	H11L	10	H7L	50	Central	Note 1

Station Name	Bus Name	Available Station Capacity (MW)	Supply Circuit 1	Availability (MW)	Supply Circuit 2	Availability (MW)	Area	Area Limit (MW)
Toronto MAIN TS	A1A2	5	H11L	10	H7L	50	Central	Note 1
Toronto MAIN TS	A3A4	5	H11L	10	H7L	50	Central	Note 1
TRAFALGAR TS	Total	63	T38B	50	T39B	50	Central	Note 1
TROUT LAKE TS	Total	81	H24S	100	W71D	150	Northeast	300
UPLANDS MTS #2		Note 3	A8M	90			East	1500
VALORA DS	Total	2	29M1	0			Northwest	100
VANSICKLE TS	Total	18	D10S	0	D9HS	0	Central	Note 1
VAUGHAN MTS #2		Note 3	V71P	50	V75P	50	Central	Note 1
VAUGHAN MTS #3		Note 3	V43	50	V44	50	Central	Note 1
VERMILION BAY DS	Total	4	K3D	0			Northwest	100
VERNER DS	Total	6	L1S	50			Northeast	300
VINELAND DS	Total	14	Q2AH	0			Central	Note 1
VINELAND DS	T1	14	Q2AH	0			Central	Note 1
VINELAND DS	T2	16	Q2AH	0			Central	Note 1
WALKER TS	Total	62	Z1E	- (Note 2)	Z7E	- (Note 2)	West of London	150
WALLACE TS	Total	15	D2M	0			Central	Note 1
WALLACE TS	T3	24	D2M	0			Central	Note 1
WALLACE TS	T4	0	D2M	0			Central	Note 1
WALLACEBURG TS	Total	26	N5K	- (Note 2)			West of London	150
WANSTEAD TS	Total	0	S2N	0			West of London	150
WANSTEAD TS	T1T2	21	S2N	0			West of London	150
WANSTEAD TS	T3	0	S2N	0			West of London	150
WARDEN TS	Total	97	C14L	50	C17L	50	Central	Note 1
WARDEN TS	J	48	C14L	50	C17L	50	Central	Note 1
WARDEN TS	Q	49	C14L	50	C17L	50	Central	Note 1
WARREN DS	Total	6	L1S	50			Northeast	300
WARREN DS	T1	5	L1S	50			Northeast	300
WARREN DS	T2	5	L1S	50			Northeast	300
WATERLOO NORTH MTS 3		Note 3	D6V	240	D7V	240	Central	Note 1
WAUBAUSHENE TS	Total	60	E26	210	E27	210	Central	Note 1
WENDOVER DS	Total	15	79M1	50			East	1500
WENDOVER DS	T1	14	79M1	50			East	1500
WENDOVER DS	T2	15	79M1	50			East	1500
WESTON LAKE DS	Total	7	T61S	20			Northeast	300
WHARNCLIFFE DS	Total	4	T1B	0			Northeast	300
WHITBY TS - 27.6 kV DESN1 (T1&T2) - BY	BY	11	H24C	50	H26C	50	East	1500
WHITBY TS - 44 kV DESN1 (T1&T2) - EZ	EZ	11	H24C	50	H26C	50	East	1500
WHITBY TS - 44kV DESN2 (T3&T4)	T3T4	120	B23C	350	M29C	200	East	1500
WHITE RIVER DS	Total	0	M2W	20			Northwest	100
WHITEFISH DS	Total	5	S2B	50			Northeast	300
WILHAVEN DS	Total	26	H9A	50			East	1500
WILHAVEN DS	T1	21	H9A	50			East	1500
WILHAVEN DS	T2	21	H9A	50			East	1500
WILSON TS DESN 1	Total	110	B23C	350	M29C	200	East	1500
WILSON TS DESN 2	Total	107	B23C	350	M29C	200	East	1500
WILTSHIRE TS DESN 1	T1T6	55	K1W	10	K3W	10	Central	Note 1
WINDSOR MALDEN TS	Total	40	C21J	- (Note 2)	C22J	- (Note 2)	West of London	150
WINDSOR MALDEN TS	B	0	C21J	- (Note 2)	C22J	- (Note 2)	West of London	150
WINDSOR MALDEN TS	Y	40	C21J	- (Note 2)	C22J	- (Note 2)	West of London	150
WINGHAM TS	Total	58	B22D	0	B23D	0	Bruce	0
WINONA TS	Total	52	Q2AH	0			Central	Note 1
WOLVERTON DS	Total	19	D1W	90			Central	Note 1
WOLVERTON DS	T1	15	D1W	90			Central	Note 1
WOLVERTON DS	T2	15	D1W	90			Central	Note 1
WONDERLAND TS	Total	71	N21W	80	N22W	70	West of London	150
WOODBRIDGE TS	BY	Note 3	V43	50	V44	50	Central	Note 1
WOODBRIDGE TS 27.6	Total	11	V43	50	V44	50	Central	Note 1
WOODBRIDGE TS 44 kV	QE	0	V43	50	V44	50	Central	Note 1
WOODROFFE TS	T1T2	22	C7BM	0	F10MV	110	East	1500
WOODROFFE TS	T3T4	22	C7BM	0	F10MV	110	East	1500
WOODSTOCK TS	Total	73	W7W	110	W12W	110	West of London	150

Note 1: Not expected to be limiting

Note 2: Some of the cells for circuit availability for West of London Area Circuits are marked with a dash. This is due to the fact that the OPA has received a directive from the Minister of Energy and Infrastructure to reserve 260 MW of bulk transmission capacity in Essex County for generating facilities whose proponents have signed a province-wide framework agreement with the Province. The connection points for these renewable generation projects have not been finalized at this time. We will update this Table once more information becomes available.

Note 3: Under review, please contact OPA at FIT.Connectinfo@powerauthority.on.ca with station name

Revised: Oct. 2, 2009

Appendix B

Hydro One Distribution Connections Allocated Capacity List

As per Distribution System Code this list represents the Allocated Capacity on stations owned by Hydro One as of October 14, 2009.

Hydro One intends to update the list of allocated capacity on a weekly basis.

Connection Impact Assessments (CIAs) in progress will result in changes to the Allocated Capacities as the CIAs are completed.

Example Station

STATION NAME				
Station Total Capacity = XX MW				
Bus Capacity (MW)	Bus 1 Name = Capacity in MW		Bus 2 Name = Capacity in MW	
	Feeder 1 Name	Feeder 2 Name	Feeder 3 Name	Feeder 4 Name
Allocated Capacity (MW)	Total MW on Feeder 1	Total MW on Feeder 2	Total MW on Feeder 3	Total MW on Feeder 4

In this box there will be a hyperlink(s) to an upstream TS or downstream DS if applicable.

NOTE:

Allocations to the left of the double red line are on bus 1 and contribute to bus 1's allocated capacity. They also contribute to the entire station's allocated capacity.

Allocations to the right of the double red line are on bus 2 and contribute to bus 2's allocated capacity. They also contribute to the entire station's allocated capacity.

ADDISON DS	
Capacity = 3.4 MW	
	F2
Allocated Capacity (MW)	0

ADDISON DS is downstream of BROCKVILLE TS M6

AGIMAK DS		
Capacity = 7 MW		
	F1	F2
Allocated Capacity (MW)	0	0

AGINCOURT TS											
Capacity = Sum of Buses MW											
Bus Capacity (MW)	B = 10.8						Y = 10.8				
	M2	M4	M6	M8	M10	M12	M1	M3	M5	M7	M11
Allocated Capacity (MW)	0	0	0	0	0	0	0	0	0	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

ALBION TS
Capacity = Sum of Buses MW
For any information or inquiries please contact Hydro Ottawa

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

ALEXANDER DS	
Capacity = 16 MW	
	F1
Allocated Capacity (MW)	11.9

ALEXANDER DS is downstream of SOUTH MARCH TS M5

ALLANBURG TS			
Capacity = 21.8 MW			
	M6	M7	M8
Allocated Capacity (MW)	0	0	19

ALLISTON TS						
Capacity = 61.5 MW						
	M1	M2	M3	M4	M5	M6
Allocated Capacity (MW)	9	0	20	10	0	20

ALMONTE TS			
Capacity = 29.1 MW			
Bus Capacity (MW)	J = 21.8	Q = 28.7	
	M25	M26	M28
Allocated Capacity (MW)	15	0	10

ARDOCH DS		
Capacity = 6.5 MW		
	F1	F2
Allocated Capacity (MW)	0	0

ARMITAGE TS DESN 1								
Capacity = 118 MW								
	M11	M12	M13	M14	M21	M22	M23	M24
Allocated Capacity (MW)	0	0	0	0	0	30	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

ARMITAGE TS DESN 2								
Capacity = 85.2 MW								
	M31	M32	M33	M34	M41	M42	M43	M44
Allocated Capacity (MW)	0	20	0	0	0	0	1.5	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

ARNPRIOR TS		
Capacity = 33.1 MW		
	M1	M2
Allocated Capacity (MW)	10	20

AYLMER TS		
Capacity = 10 MW		
	M1	M2
Allocated Capacity (MW)	0	0.8

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

AZILDA DS	
Capacity = 4.6 MW	
	F1
Allocated Capacity (MW)	0.2

AZILDA DS is downstream of CLARABELLE TS M8

BARRIE TS							
Capacity = 68.5 MW							
	M1	M2	M3	M4	M5	M6	M7
Allocated Capacity (MW)	0	0	0	0	0	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

BASIN TS
Capacity = Sum of Buses MW
For any information or inquiries please contact Toronto Hydro

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

BATHURST TS DESN 1
Capacity = Sum of Buses MW
For any information or inquiries please contact Toronto Hydro

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

BATHURST TS DESN 2
Capacity = Sum of Buses MW
For any information or inquiries please contact Toronto Hydro

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

BATTERSEA DS			
Capacity = 8 MW			
Bus Capacity (MW)	T1 = 7.1		T2 = 7.7
	F1	F2	F3
Allocated Capacity (MW)	0.5	0	0

BEACH TS - DESN1
Capacity = Sum of Buses MW
For any information or inquiries please contact Horizon Utilities Corporation

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

BEACH TS - DESN2
Capacity = Sum of Buses MW
For any information or inquiries please contact Horizon Utilities Corporation

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

BEACHBURG DS	
Capacity = 4 MW	
	F2
Allocated Capacity (MW)	0.6

BEACHBURG DS is downstream of COBDEN TS M2

BEAMSVILLE TS				
Capacity = 32.4 MW				
	M1	M2	M3	M4
Allocated Capacity (MW)	10	20	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

BEARDMORE DS				
Capacity = 6.1 MW				
	F1	F2	F3	F4
Allocated Capacity (MW)	0	0.7	0	0

BEAVERTON TS								
Capacity = 71.6 MW								
	M23	M24	M25	M26	M27	M28	M29	M30
Allocated Capacity (MW)	18	9.9	0	20	20.1	0	0	0

PORT BOLSTER DS is downstream of BEAVERTON TS M27

BELLE RIVER TS				
Capacity = 26.9 MW				
	M1	M2	M3	M4
Allocated Capacity (MW)	0.5	19.9	0	0

BELLEVILLE TS									
Capacity = 80.5 MW									
	M1	M2	M3	M4	M5	M6	M7	M8	M9
Allocated Capacity (MW)	0	20	0	0	20.5	20	20	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

STIRLING DS is downstream of BELLEVILLE TS M5

BERMONDSEY TS DESN 1						
Capacity = Sum of Buses MW						
Bus Capacity (MW)	J = 9.9			Q = 10.8		
	M23	M25	M27	M24	M26	M28
Allocated Capacity (MW)	0	0	0	0	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

BERMONDSEY TS DESN 2												
Capacity = Sum of Buses MW												
Bus Capacity (MW)	Y = 10.8						B = 10.8					
	M2	M4	M6	M8	M10	M12	M1	M3	M5	M7	M9	M11
Allocated Capacity (MW)	0	0	0	0	0	0	0	0	0	0	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

BILBERRY CREEK TS						
Capacity = 59.4 MW						
	M1	M2	M3	M4	M5	M6
Allocated Capacity (MW)	0	0	0	0	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

BIRCH TS								
Capacity = 65.1 MW								
	M1	M2	M3	M4	M5	M6	M7	M8
Allocated Capacity (MW)	0	0	0	0	0	0	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

BIRMINGHAM TS DESN 1										
Capacity = Sum of Buses MW										
Bus Capacity (MW)	QJ = 5.4								BY = 5.4	
	M1	M2	M3	M4	M5	M6	M7	M8	M21	M22
Allocated Capacity (MW)	0	0	0	0	0	0	0	0	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

BIRMINGHAM TS DESN 2							
Capacity = Sum of Buses MW							
Bus Capacity (MW)	EZ = 2.7					KD = 21.6	
	M10	M11	M12	M13	M14	M71	M81
Allocated Capacity (MW)	0	0	0	0	0	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

BIRR DS	
Capacity = 3.7 MW	
	F2
Allocated Capacity (MW)	0.3

BIRR DS is downstream of CLARKE TS M2

BRACEBRIDGE TS	
Capacity = 40 MW	
	M20
Allocated Capacity (MW)	0

BRAMALEA TS DESN 1												
Capacity = Sum of Buses MW												
Bus Capacity (MW)	Y = 5.4						B = 5.4					
	M2	M4	M6	M8	M10	M12	M1	M3	M5	M7	M9	M11
Allocated Capacity (MW)	0	0	0	0	0	0	0	0	0	0	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

BRAMALEA TS DESN 2							
Capacity = 0 MW							
	M23	M25	M27	M29	M24	M26	M28
Allocated Capacity (MW)	0	0	0	0	0	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

BRAMALEA TS DESN 3

Capacity = 0 MW

	M44	M46	M48	M50	M43	M45	M47
Allocated Capacity (MW)	0	0	0	0	0	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

BRANT TS

Capacity = 61 MW

	M11	M12	M13	M14	M21	M22	M23	M24
Allocated Capacity (MW)	0	0	0	10	19.9	20	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

BRANTFORD TS

Capacity = Sum of Buses MW

Bus Capacity (MW)	Y = 5.4					Z = 5.4				
	M21	M23	M25	M27	M29	M22	M24	M26	M28	M30
Allocated Capacity (MW)	0	0	0	0	0	0	0	8.1	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

BRIDGMAN TS DESN 1

Capacity = 5.4 MW

For any information or inquiries please contact Toronto Hydro

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

BRIDGMAN TS DESN 2

Capacity = 5.4 MW

For any information or inquiries please contact Toronto Hydro

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

BRIDGMAN TS DESN 3

Capacity = 5.4 MW

For any information or inquiries please contact Toronto Hydro

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

BRIDGMAN TS DESN 4

Capacity = 5.4 MW

For any information or inquiries please contact Toronto Hydro

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

BROCKVILLE SCHOFIELD DS

Capacity = 2.1 MW

	F41
Allocated Capacity (MW)	0.1

BROCKVILLE SCHOFIELD DS is downstream of BROCKVILLE TS M3

BROCKVILLE TS

Capacity = 36 MW

	M1	M2	M3	M4	M5	M6	M7	B1R
Allocated Capacity (MW)	0	10	0.1	0	0	0	0	0.5

ADDISON DS is downstream of BROCKVILLE TS M6 | BROCKVILLE SCHOFIELD DS is downstream of BROCKVILLE TS M3 | SPENCERVILLE DS is downstream of BROCKVILLE TS B1R

BRONTE TS DESN 1

Capacity = 63.9 MW

Bus Capacity (MW)	T5 = 54.2				T6 = 54.5		
	M1	M3	M5	M7	M2	M4	M8
Allocated Capacity (MW)	0	0	0	0	0	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

BRONTE TS DESN 2

Capacity = 54 MW

	M23	M24	M25	M26	M27	M28
Allocated Capacity (MW)	0	0	0	0	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

BROWN HILL TS

Capacity = 82.5 MW

	M1	M2	M3	M4	M11	M12
Allocated Capacity (MW)	10	0	20	0	20	30

BUCHANAN TS

Capacity = Sum of Buses MW

Bus Capacity (MW)	B = 30.4						Y = 30.5					
	M21	M23	M25	M27	M29	M37	M22	M24	M26	M28	M30	M38
Allocated Capacity (MW)	20	0	0	0	0	0	19.9	0	0	0	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

BUNTING TS

Capacity = Sum of Buses MW

For any information or inquiries please contact Horizon Utilities Corporation

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

BURLEIGH DS

Capacity = 2.2 MW

	F1	F2
Allocated Capacity (MW)	0	0

BURLINGTON TS

Capacity = Sum of Buses MW

Bus Capacity (MW)	BY = 51.8						QJ = 52.7					
	M1	M2	M3	M4	M5	M6	M31	M32	M33	M34	M35	M36
Allocated Capacity (MW)	0	0	0	0	0	0	0	0	0	0	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

BUTTERNUT DS

Capacity = 11.4 MW

	F2
Allocated Capacity (MW)	0

BUTTERNUT DS is downstream of FRONTENAC TS M3

BUTTONVILLE TS

Capacity = Sum of Buses MW

Bus Capacity (MW)	Q = 10.8						Z = 9.8					
	M1	M3	M5	M7	M9	M11	M2	M4	M6	M8	M10	M12
Allocated Capacity (MW)	0	0	0	0	0	0	0	0	0	0	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

CALEDONIA TS

Capacity = 40 MW

	M3	M4	M5	M6
Allocated Capacity (MW)	0	20	20	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

CALSTOCK DS

Capacity = 4.9 MW

	F1	F2
Allocated Capacity (MW)	0	0

CAMPBELL TS - DESN 1

Capacity = Sum of Buses MW

Bus Capacity (MW)	BY = 5.4								QJ = 5.4							
	M11	M12	M13	M14	M21	M22	M23	M24	M31	M32	M33	M34	M41	M42	M43	M44
Allocated Capacity (MW)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

CAMPBELL TS DESN 2								
Capacity = 30.2 MW								
	M51	M52	M53	M54	M61	M62	M63	M64
Allocated Capacity (MW)	0	0	0	0	0	0	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

CARDIFF TS										
Capacity = 70 MW										
	M1	M2	M3	M4	M5	M6	M7	M8	M9	M10
Allocated Capacity (MW)	0	0	0	0	0	0	0	0	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

CARLAW TS
Capacity = Sum of Buses MW
For any information or inquiries please contact Toronto Hydro

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

CARLING TS
Capacity = Sum of Buses MW
For any information or inquiries please contact Hydro Ottawa

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

CARLTON TS DESN 1				
Capacity = 18.1 MW				
	M13	M14	M15	M16
Allocated Capacity (MW)	0	0	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

CARLTON TS DESN 2														
Capacity = Sum of Buses MW														
Bus Capacity (MW)	BY = 0						KH = 5.4							
	M12	M20	M25	M11	M10	M21	M7	M17	M18	$ A1	A6	A2	A3	A4
Allocated Capacity (MW)	0	0	0	0	0	0	0	3.6	0	0	0	0	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

CECIL TS DESN 1
Capacity = Sum of Buses MW
For any information of inquiries please contact Toronto Hydro

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

CECIL TS DESN 2
Capacity = Sum of Buses MW
For any information of inquiries please contact Toronto Hydro

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

CEDAR TS DESN 1
Capacity = Sum of Buses MW
For any information or inquiries please contact Guelph Hydro

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

CEDAR TS DESN 2
Capacity = 35.3 MW
For any information or inquiries please contact Guelph Hydro

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

CENTRALIA TS				
Capacity = 29.4 MW				
	M1	M2	M3	M4
Allocated Capacity (MW)	0.3	0	0	18

CHAPLEAU DS		
Capacity = 0 MW		
	F3	F4
Allocated Capacity (MW)	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

CHARLES TS DESN 1
Capacity = Sum of Buses MW
For any information or inquiries please contact Toronto Hydro

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

CHARLES TS DESN 2
Capacity = Sum of Buses MW
For any information or inquiries please contact Toronto Hydro

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

CHERRYWOOD TS								
Capacity = 77.4 MW								
	M1	M2	M3	M4	M5	M6	M7	M8
Allocated Capacity (MW)	0	0	0	0	0	0	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

CHESTERVILLE TS		
Capacity = 32.1 MW		
	M2	M4
Allocated Capacity (MW)	20	10

CLARABELLE TS					
Capacity = 76.5 MW					
	M4	M5	M6	M7	M8
Allocated Capacity (MW)	0	27	18	27	0.2

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

AZILDA DS is downstream of CLARABELLE TS M8

CLARENCE DS		
Capacity = 2 MW		
	F1	F2
Allocated Capacity (MW)	0	0

CLARKE TS								
Capacity = 70.5 MW								
	M1	M2	M3	M4	M5	M6	M7	M8
Allocated Capacity (MW)	0	20.3	0	0	0	0	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

BIRR DS is downstream of CLARKE TS M2

CLEARWATER BAY DS		
Capacity = 4.2 MW		
	F1	F2
Allocated Capacity (MW)	0	0

COBDEN DS			
Capacity = 7.6 MW			
	F2	F3	F4
Allocated Capacity (MW)	0	0	0

COBDEN TS		
Capacity = 13.7 MW		
Bus Capacity (MW)	T1 = 10.8	T2 = 12.3
	M6	M2
Allocated Capacity (MW)	9	1.9

BEACHBURG DS is downstream of COBDEN TS M2

NORTHCOTE DS is downstream of COBDEN TS M2

COBOCONK DS	
Capacity = 6 MW	
	F2
Allocated Capacity (MW)	0.5

COBOCONK DS is downstream of LINDSAY TS M7

COCHRANE WEST DS		
Capacity = 3.8 MW		
	F1	F2
Allocated Capacity (MW)	1	0

CONISTON TS		
Capacity = 0 MW		
	M1	M5
Allocated Capacity (MW)	0	0

CONSTANCE DS			
Capacity = 17.7 MW			
Bus Capacity (MW)	T1 = 13.7	T2 = 16.1	
	F1	F2	F4
Allocated Capacity (MW)	0	10.8	0.1

COOKSVILLE TS DESN 1						
Capacity = 57.1 MW						
	M10	M12	M14	M11	M13	M9
Allocated Capacity (MW)	0	0	0	0	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

COOKSVILLE TS DESN 2						
Capacity = 59.2 MW						
	M17	M19	M21	M18	M20	M22
Allocated Capacity (MW)	0	0	0	0	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

CRAIG DS			
Capacity = 10 MW			
	F1	F2	F3
Allocated Capacity (MW)	0	0	0

CRAWFORD TS											
Capacity = 61.6 MW											
	M5	M6	M7	M8	M8	M9	M10	M11	M12	M13	M14
Allocated Capacity (MW)	0	0	0	0	0	0	0	0	0	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

CROSBY TS DESN 1			
Capacity = 22.9 MW			
Bus Capacity (MW)	T1 = 21.4		T2 = 21.5
	M3	M5	M6
Allocated Capacity (MW)	0	0	20

CROSBY TS DESN 2		
Capacity = 46.8 MW		
	M1	M2
Allocated Capacity (MW)	27	20

CROW RIVER DS		
Capacity = 5.3 MW		
Bus Capacity (MW)	T3 = 3.7	T4 = 5.2
	F1	F2
Allocated Capacity (MW)	0	0

CROWLAND TS										
Capacity = 57.1 MW										
	M13	M14	M15	M16	M17	M18	M19	M20	M21	M22
Allocated Capacity (MW)	10	0	0	0	0	20	19	0	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

CRYSLER DS	
Capacity = 3.5 MW	
	F2
Allocated Capacity (MW)	0.1

CRYSLER DS is downstream of ST ISIDORE TS M2

CRYSTAL FALLS TS		
Capacity = 18.3 MW		
	M1	M2
Allocated Capacity (MW)	10	8.5

CUMBERLAND DS				
Capacity = 4.9 MW				
Bus Capacity (MW)	T1 = 4.6		T2 = 3.2	
	F2	F4	F1	F3
Allocated Capacity (MW)	0	0	0	0

CUMBERLAND TS										
Capacity = Sum of Buses MW										
Bus Capacity (MW)	B = 5.4					Q = 5.4				
	M22	M24	M26	M28	M30	M21	M23	M25	M27	M29
Allocated Capacity (MW)	0	0	0	0	0	0	0	0	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

DEEP RIVER DS				
Capacity = 12.3 MW				
Bus Capacity (MW)	T1 = 5.4	T2 = 6.2		T3 = 6.4
	F1	F2	F3	F5
Allocated Capacity (MW)	0	0	0	0

DES JOACHIMS DS			
Capacity = 6.6 MW			
	F1	F2	F3
Allocated Capacity (MW)	0	0	0

DETWEILER TS			
Capacity = 21.6 MW			
	M11	M12	M13
Allocated Capacity (MW)	0	7.8	10

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

DOBBIN DS		
Capacity = 14.6 MW		
Bus Capacity (MW)	T1 = 13.4	T2 = 13.2
	F1	F2
Allocated Capacity (MW)	0	0

DOBBIN TS								
Capacity = 86.8 MW								
	M1	M2	M3	M4	M5	M6	M7	M8
Allocated Capacity (MW)	34	10	0	0	35	0	8	0

DOUGLAS POINT TS

Capacity = 39 MW

	M1	M2	M3	M4	M5	M6	M8
Allocated Capacity (MW)	0	0	0	8.5	0	14.7	10

REID CORNERS DS is downstream of DOUGLAS POINT TS M6

DRYDEN RURAL DS

Capacity = 4.7 MW

	F2
Allocated Capacity (MW)	2.6

DRYDEN RURAL DS is downstream of DRYDEN TS M1

DRYDEN TS

Capacity = 20.4 MW

	M1	M3
Allocated Capacity (MW)	2.6	10

DRYDEN RURAL DS is downstream of DRYDEN TS M1

DUFFERIN TS DESN 1

Capacity = Sum of Buses MW

For any information or inquiries please contact Toronto Hydro

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

DUFFERIN TS DESN 2

Capacity = Sum of Buses MW

For any information or inquiries please contact Toronto Hydro

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

DUNDAS TS

Capacity = 69.4 MW

	M1	M2	M3	M4	M5	M6	M7	M8
Allocated Capacity (MW)	0	0	0	0	0	0	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

DUNDAS TS #2

Capacity = 51.8 MW

	M11	M12	M13	M14	M15	M16
Allocated Capacity (MW)	0	0	0	0	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

DUNNVILLE TS

Capacity = 20 MW

	M1	M2
Allocated Capacity (MW)	0	19.9

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

DUPLEX TS DESN 1

Capacity = Sum of Buses MW

For any information or inquiries please contact Toronto Hydro

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

DUPLEX TS DESN 2

Capacity = Sum of Buses MW

For any information or inquiries please contact Toronto Hydro

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

DYMOND TS

Capacity = 16.9 MW

	M1	M2	M3
Allocated Capacity (MW)	0	0	9.5

EAR FALLS TS

Capacity = 10.4 MW

	M1
Allocated Capacity (MW)	0

EDGEWARE TS

Capacity = Sum of Buses MW

Bus Capacity (MW)	B = 8.1				Y = 8.1				
	M1	M3	M5	M7	M2	M4	M6	M8	M10
Allocated Capacity (MW)	0	0	0	0	0	0	0	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

ELGIN TS DESN 1

Capacity = Sum of Buses MW

Bus Capacity (MW)	DK = 5.4								JQ = 1.9											
	M41	M42	M43	M44	M45	M46	M47	M48	M22	M23	M24	M25	M26	M27	M28	M30	M31	M32	M33	M34
Allocated Capacity (MW)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

ELGIN TS DESN 2

Capacity = 24.8 MW

	M51	M52	M53	M61	M62	M63
Allocated Capacity (MW)	0	0	0	0	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

ELLESMERE TS

Capacity = Sum of Buses MW

Bus Capacity (MW)	J = 10.8						Q = 10.8					
	M21	M23	M25	M27	M29	M31	M22	M24	M26	M28	M30	M32
Allocated Capacity (MW)	0	0	0	0	0	0	0	0	0	0	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

ELLIOT LAKE TS

Capacity = 25 MW

	M1	M3
Allocated Capacity (MW)	9	5.5

ELMIRA TS

Capacity = 30.4 MW

	M1	M2	M3
Allocated Capacity (MW)	2.8	21	2.9

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

ERINDALE TS DESN 1

Capacity = Sum of Buses MW

Bus Capacity (MW)	E = 10.8						Q = 10.8					
	M32	M34	M36	M38	M40	M42	M31	M33	M35	M37	M39	M41
Allocated Capacity (MW)	0	0	0	0	0	0	0	0	0	0	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

ERINDALE TS DESN 2

Capacity = 93.6 MW

	M23	M24	M25	M26	M27	M28	M29	M30
Allocated Capacity (MW)	0	0	0	0	0	0	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

ERINDALE TS DESN 3

Capacity = 102.9 MW

	M1	M2	M3	M4	M5	M6	M7	M8
Allocated Capacity (MW)	0	0	0	0	0	0	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

ESPANOLA DS

Capacity = 4 MW

	F1
Allocated Capacity (MW)	1

ESPANOLA DS is downstream of ESPANOLA TS M1

ESPANOLA TS		
Capacity = 18.1 MW		
	M1	M2
Allocated Capacity (MW)	1	5.6

ESPANOLA DS is downstream of ESPANOLA TS M1

ESPLANADE TS										
Capacity = Sum of Buses MW										
Bus Capacity (MW)	Q1Q2 = 17.1				Cumulative = 52.3158815121594					
	M11	M12	M13	M14	M5	M6	M7	M8	M10	M11
Allocated Capacity (MW)	0	0	0	0	0	0	0	0	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

ESSEX TS
Capacity = 52.3 MW
For any information or inquiries please contact EnWin Utilities

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

ETON DS			
Capacity = 8.3 MW			
	F1	F2	F3
Allocated Capacity (MW)	0	0	0

EVERETT TS				
Capacity = 63.7 MW				
	M5	M6	M7	M8
Allocated Capacity (MW)	30	10	10	10

FAIRBANK TS DESN 1						
Capacity = 62.9 MW						
	M11	M12	M7	M3	M5	M8
Allocated Capacity (MW)	0	0	0	0	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

FAIRBANK TS DESN 2								
Capacity = 56.3 MW								
	M1	M10	M2	M23	M24	M4	M6	M9
Allocated Capacity (MW)	0	0	0	0	0	0	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

FAIRCHILD TS DESN 1												
Capacity = Sum of Buses MW												
Bus Capacity (MW)	B = 10.8						Y = 10.8					
	M1	M3	M5	M7	M9	M11	M2	M4	M6	M8	M10	M12
Allocated Capacity (MW)	0	0	0	0	0	0	0	0	0	0	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

FAIRCHILD TS DESN 2												
Capacity = Sum of Buses MW												
Bus Capacity (MW)	J = 4.5						Q = 10.8					
	M21	M23	M25	M27	M29	M31	M22	M24	M26	M28	M30	M32
Allocated Capacity (MW)	0	0	0	0	0	0	0	0	0	0	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

FALLOWFIELD DS		
Capacity = 14.5 MW		
	F1	F2
Allocated Capacity (MW)	9.8	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

FAUQUIER DS		
Capacity = 2 MW		
	F1	F2
Allocated Capacity (MW)	0	0

FERGUS TS						
Capacity = 98 MW						
	M1	M2	M3	M4	M7	M8
Allocated Capacity (MW)	35.5	30	32	0	0	0

FINCH TS DESN 1												
Capacity = Sum of Buses MW												
Bus Capacity (MW)	B = 10.8						Y = 10.8					
	M1	M3	M5	M7	M9	M11	M2	M4	M6	M8	M10	M12
Allocated Capacity (MW)	0	0	0	0	0	0	0	0	0	0	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

FINCH TS DESN 2												
Capacity = Sum of Buses MW												
Bus Capacity (MW)	Q = 10.8						J = 10.8					
	M22	M24	M26	M28	M30	M32	M21	M23	M25	M27	M29	M31
Allocated Capacity (MW)	0	0	0	0	0	0	0	0	0	0	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

FOREST JURA DS				
Capacity = 18.2 MW				
Bus Capacity (MW)	T1 = 15.5		T2 = 15.5	
	F1	F3	F2	F4
Allocated Capacity (MW)	0	0	16.5	0

SPRINGVALE DS is downstream of FOREST JURA DS F1

FOREST LEA DS				
Capacity = 7.5 MW				
Bus Capacity (MW)	T2 = 6.1		T1 = 6.7	
	F3	F4	F1	F2
Allocated Capacity (MW)	0	0	0	0

FORT FRANCES TS	
Capacity = 53 MW	
	M1
Allocated Capacity (MW)	10

FORT WILLIAM TS
Capacity = 69.7 MW
For any information or inquires please contact Thunder Bay Hydro

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

FRONTENAC TS						
Capacity = 64.3 MW						
	M1	M2	M3	M4	M5	M8
Allocated Capacity (MW)	30	0	0	0	0	30

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

BUTTERNUT DS is downstream of FRONTENAC TS M3

GAGE TS DESN 1
Capacity = 0 MW
For any information or inquires please Horizon Utilities

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

GAGE TS DESN 2
Capacity = 0 MW
For any information or inquires please Horizon Utilities

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

GAGE TS DESN 3
Capacity = 0 MW
For any information or inquires please Horizon Utilities

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

GAGE TS DESN 4
Capacity = 79.7 MW
For any information or inquires please Horizon Utilities

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

GALT TS
Capacity = Sum of Buses MW
For any information or inquiries please contact Cambridge North Dumfries Hydro (CND)

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

GERRARD TS DESN 1
Capacity = 19.3 MW
For any information or inquiries please contact Toronto Hydro

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

GERRARD TS DESN 2
Capacity = 24.1 MW
For any information or inquiries please contact Toronto Hydro

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

GLEN SANDFIELD DS	
Capacity = 3.7 MW	
	F3
Allocated Capacity (MW)	0.1

GLEN SANDFIELD DS is downstream of LONGUEUIL TS M23

GLENDALE TS								
Capacity = Sum of Buses MW								
Bus Capacity (MW)	BJ = 3.2				DQ = 0.8			
	M31	M32	M33	M34	M5	M8	M23	M24
Allocated Capacity (MW)	0	0	0	0	0	0	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

GLENDALE TS DESN 2		
Capacity = 0 MW		
	M16	M9
Allocated Capacity (MW)	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

GLENGARRY DS	
Capacity = 8.3 MW	
	F1
Allocated Capacity (MW)	7.5

GLENGARRY DS is downstream of ST ISIDORE TS M4

GLENGROVE TS DESN 1
Capacity = 24.2 MW
For any information or inquiries please contact Toronto Hydro

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

GLENGROVE TS DESN 2
Capacity = 23.7 MW
For any information or inquiries please contact Toronto Hydro

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

GODERICH TS				
Capacity = 0.7 MW				
	M1	M2	M3	M4
Allocated Capacity (MW)	0	0	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

GOREWAY TS DESN1												
Capacity = Sum of Buses MW												
Bus Capacity (MW)	B = 10.8						Y = 10.8					
	M41	M43	M45	M47	M49	M51	M42	M44	M46	M48	M50	M52
Allocated Capacity (MW)	0	0	0	0	0	0	0	0	0	0	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

GRAND BEND EAST DS		
Capacity = 17 MW		
Bus Capacity (MW)	T1 = 15	T2 = 15.3
	F1	F2
Allocated Capacity (MW)	15	0

GREELY DS			
Capacity = 20.7 MW			
Bus Capacity (MW)	T1 = 18	T2 = 18.6	
	F3	F2	F4
Allocated Capacity (MW)	10	10	0

HALTON TS												
Capacity = Sum of Buses MW												
Bus Capacity (MW)	J = 50.3						Q = 50.4					
	M22	M24	M26	M28	M30	M32	M21	M23	M25	M27	M29	M31
Allocated Capacity (MW)	0	0	0	0	0	0	0	0	0	0	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

HANLON TS						
Capacity = 29.6 MW						
	M11	M12	M13	M21	M22	M23
Allocated Capacity (MW)	0	0	0	0	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

HANOVER TS						
Capacity = 67.7 MW						
	M1	M2	M3	M4	M5	H1E
Allocated Capacity (MW)	0	9	0	18	18	18

HARROWSMITH DS				
Capacity = 9.7 MW				
Bus Capacity (MW)	T1 = 7.8		T2 = 7.8	
	F2	F3	F4	F5
Allocated Capacity (MW)	0	0	0	0

HAVELOCK TS					
Capacity = 29.1 MW					
	M1	M2	M3	M4	M6
Allocated Capacity (MW)	0	10	9.8	6.7	0

HAWTHORNE TS					
Capacity = 75.6 MW					
	M1	M2	M3	M4	M5
Allocated Capacity (MW)	25	0	0	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

OSGOODE DS is downstream of HAWTHORNE TS M1

HEARST TS			
Capacity = 24.9 MW			
	M1	M2	M3
Allocated Capacity (MW)	0	16	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

HERRIDGE LAKE DS		
Capacity = 2.1 MW		
	F1	F2
Allocated Capacity (MW)	0	0

HIGHBURY TS								
Capacity = 67 MW								
	M11	M12	M13	M14	M15	M16	M17	M18
Allocated Capacity (MW)	10	0	0	0	0	0	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

HINCHEY TS
Capacity = Sum of Buses MW
For any information or inquiries please contact Hydro Ottawa

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

HINCHINBROOKE DS			
Capacity = 4.6 MW			
	F1	F2	F3
Allocated Capacity (MW)	0	0	0

HORNER TS										
Capacity = Sum of Buses MW										
Bus Capacity (MW)	Y = 45.7					B = 47.6				
	M2	M4	M6	M8	M10	M1	M3	M5	M7	M9
Allocated Capacity (MW)	0	0	0	0	0	0	0	0	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

HORNING TS																
Capacity = Sum of Buses MW																
Bus Capacity (MW)	B = 33.8										Q = 33.8					
	M2	M3	M4	M5	M6	M7	M8	M9	M10	M11	M45	M46	M47	M48	M49	M50
Allocated Capacity (MW)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

HOYLE DS		
Capacity = 13.3 MW		
	F1	F2
Allocated Capacity (MW)	0	0

INGERSOLL TS								
Capacity = Sum of Buses MW								
Bus Capacity (MW)	E = 10.8				Z = 10.8			
	M43	M45	M49	M51	M44	M46	M50	M52
Allocated Capacity (MW)	0	10	0	0	0	10	0	0

KINTORE DS is downstream of INGERSOLL TS M43

KIRKTON DS is downstream of INGERSOLL TS M43

IROQUOIS FALLS DS			
Capacity = 5.6 MW			
	F1	F2	F3
Allocated Capacity (MW)	0	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

JARVIS TS							
Capacity = 9.1 MW							
	M1	M2	M3	M4	M5	M6	M7
Allocated Capacity (MW)	0	0	0	0	0	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

JELLICOE DS	
Capacity = 0.9 MW	
	F1
Allocated Capacity (MW)	0

JOHN TS DESN 1
Capacity = Sum of Buses MW
For any information or inquiries please contact Toronto Hydro

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

JOHN TS DESN 2
Capacity = Sum of Buses MW
For any information or inquiries please contact Toronto Hydro

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

JOHN TS DESN 3
Capacity = Sum of Buses MW
For any information or inquiries please contact Toronto Hydro

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

KAPUSKASING TS				
Capacity = 46.2 MW				
	M1	M2	M3	M4
Allocated Capacity (MW)	10	0	17.5	16

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

KEITH TS DESN 1						
Capacity = 58.2 MW						
	M1	M2	M3	M4	M5	M6
Allocated Capacity (MW)	0	0	25	10	1	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

KENILWORTH DS	
Capacity = 2.4 MW	
	F1
Allocated Capacity (MW)	0

KENILWORTH DS is downstream of PALMERSTON TS M2

KENORA DS				
Capacity = 8.1 MW				
	F1	F2	F3	F4
Allocated Capacity (MW)	0	0	0	0

KENT TS DESN1												
Capacity = Sum of Buses MW												
Bus Capacity (MW)	Y T1T2 = 54						B T1T2 = 50					
	M2	M4	M6	M8	M16	M18	M1	M3	M5	M7	M15	M17
Allocated Capacity (MW)	19.8	0	0	0	19.9	14.5	19.9	0	0	0	18.4	9.9

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

KENT TS DESN2		
Capacity = 28.3 MW		
	M21	M22
Allocated Capacity (MW)	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

KING EDWARD TS
Capacity = Sum of Buses MW
For any information or inquiries please contact Hydro Ottawa

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

KINGSTON GARDINER TS

Capacity = 120.5 MW

	M3	M7	M8	M9	M10	M11	M12	M13	M14	M15
Allocated Capacity (MW)	30	0	0	0	0	20.5	0	0	33	9

REDDENDALE DS is downstream of KINGSTON GARDINER TS M11

KINGSVILLE TS

Capacity = 58.9 MW

	M1	M2	M3	M4	M5	M6	M7	M8	M9	M10
Allocated Capacity (MW)	0	0	12	9	9	0	0	19	0	0

KINMOUNT DS

Capacity = 4.3 MW

	F2
Allocated Capacity (MW)	0.3

KINMOUNT DS is downstream of MINDEN TS M3

KINTORE DS

Capacity = 3.9 MW

	F1
Allocated Capacity (MW)	0

KINTORE DS is downstream of INGERSOLL TS M43

KIRKLAND LAKE TS

Capacity = 21.1 MW

	M61	M62	
Allocated Capacity (MW)	0	18	0

KIRKTON DS

Capacity = 4.3 MW

	F1
Allocated Capacity (MW)	0.3

KIRKTON DS is downstream of INGERSOLL TS M43

KLEINBURG TS 27.6 KV

Capacity = 9.9 MW

	M3	M4	M5	M6	M7	M8
Allocated Capacity (MW)	0	0	0	0	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

KLEINBURG TS 44 KV

Capacity = 18 MW

	M23	M24	M25	M26	M27	M28
Allocated Capacity (MW)	0	0.1	0	0	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

SCHOMBERG DS is downstream of KLEINBURG TS M24

LAFOREST ROAD DS

Capacity = 19.4 MW

	F1	F2
Allocated Capacity (MW)	14	0

LAKE TS DESN 1

Capacity = 57.1 MW

	M31	M32	M33	M41	M42	M43	M71	M72	M73	M81	M82	M83
Allocated Capacity (MW)	0	0	0	0	0	0	0	0	0	0	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

LAKE TS DESN 2

Capacity = Sum of Buses MW

Bus Capacity (MW)	J1J2 = 5.4						Q1Q2 = 5.4					
	M31	M32	M33	M41	M42	M43	M71	M72	M73	M81	M82	M83
Allocated Capacity (MW)	0	0	0	0	0	0	0	0	0	0	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

LAMBTON TS

Capacity = 80 MW

Bus Capacity (MW)	D T5 = 60			Y T6 = 20	
	M1	M3	M5	M2	M4
Allocated Capacity (MW)	20	20	20	20	0

LARCHWOOD TS

Capacity = 13.2 MW

	M3	M4
Allocated Capacity (MW)	0	0

LAUZON TS DESN1

Capacity = 64.1 MW

	M1	M2	M3	M4	M5	M6	M7	M8
Allocated Capacity (MW)	0	9.9	0	20	0	0	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

LAUZON TS DESN2

Capacity = 62.4 MW

	M23	M24	M25	M26	M27	M28	M29
Allocated Capacity (MW)	0	19.9	0	1	9.9	10	21

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

LEASIDE TS DESN 1

Capacity = 5.4 MW

For any information or inquiries please contact Toronto Hydro

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

LEASIDE TS DESN 2

Capacity = 5.4 MW

	M1	M2	M3	M4	M5	M6	M7	M8
Allocated Capacity (MW)	0	0	0	0	0	0	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

LESLIE TS DESN

Capacity = Sum of Buses MW

For any information or inquiries please contact Toronto Hydro

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

LESLIE TS DESN 2

Capacity = Sum of Buses MW

Bus Capacity (MW)	J = 10.8						Q = 10.8					
	M21	M23	M25	M27	M29	M31	M22	M24	M26	M28	M30	M32
Allocated Capacity (MW)	0	0	0	0	0	0	0	0	0	0	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

LINCOLN HEIGHTS TS

Capacity = Sum of Buses MW

For any information or inquiries please contact Hydro Ottawa

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

LINDSAY TS

Capacity = 84.2 MW

Bus Capacity (MW)	T1 = 70.5			T2 = 73.8		
	M3	M5	M7	M4	M6	M8
Allocated Capacity (MW)	0	0	9	20	28.5	25.5

COBOCONK DS is downstream of LINDSAY TS M7

LISGAR TS

Capacity = Sum of Buses MW

For any information or inquiries please contact Hydro Ottawa

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

LODGEROOM DS				
Capacity = 8 MW				
Bus Capacity (MW)	T1 = 8		T2 = 6.7	
	F3	F4	F1	F2
Allocated Capacity (MW)	0	0	0	0

LONGLAC TS		
Capacity = 4.1 MW		
	M1	M2
Allocated Capacity (MW)	0	0

LONGUEUIL DS	
Capacity = 8.3 MW	
	F3
Allocated Capacity (MW)	5

LONGUEUIL DS is downstream of LONGUEUIL TS M25

LONGUEUIL TS				
Capacity = 60.7 MW				
	M23	M24	M25	M26
Allocated Capacity (MW)	30.9	0	5	20.2

GLEN SANDFIELD DS is downstream of LONGUEUIL TS M23	LONGUEUIL DS is downstream of LONGUEUIL TS M25	PLANTAGENET DS is downstream of LONGUEUIL TS M26	STARDALE DS is downstream of LONGUEUIL TS M23

LONGWOOD TS				
Capacity = 48.5 MW				
	M23	M24	M25	M26
Allocated Capacity (MW)	19	20	10	0

LORNE PARK TS										
Capacity = Sum of Buses MW										
Bus Capacity (MW)	B = 10.8					J = 10.8				
	M1	M3	M5	M7	M9	M2	M4	M6	M8	M10
Allocated Capacity (MW)	0	0	0	0	0	0	0	0	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

MAIN TS
Capacity = Sum of Buses MW
For any information or inquiries please contact Toronto Hydro

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

MALVERN TS								
Capacity = Sum of Buses MW								
Bus Capacity (MW)	J = 10.8				Q = 9.9			
	M21	M31	M33	M35	M22	M32	M34	M36
Allocated Capacity (MW)	0	0	0	0	0	0	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

MANBY TS DESN 1					
Capacity = 33.9 MW					
	M1M3	M5	M7	M9	M12
Allocated Capacity (MW)	0	0	0	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

MANBY TS DESN 2						
Capacity = 35 MW						
	M13	M16	M17	M20	M21	M24
Allocated Capacity (MW)	0	0	0	0	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

MANBY TS DESN 3								
Capacity = 74.9 MW								
	M4	M6	M8	M10	M23	M25	M27	M29
Allocated Capacity (MW)	0	0	0	0	0	0	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

MANITOULIN TS		
Capacity = 27 MW		
Bus Capacity (MW)	T3 = 22.6	T4 = 26
	M25	M26
Allocated Capacity (MW)	20.6	26

MANITOUWADGE DS	
Capacity = 3.1 MW	
	F3
Allocated Capacity (MW)	0

MANITOUWADGE TS			
Capacity = 10.9 MW			
	M1	M2	M3
Allocated Capacity (MW)	0	15.6	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

MANOTICK DS				
Capacity = 6.8 MW				
Bus Capacity (MW)	T1 = 7.4		T2 = 4.8	
	F1	F2	F4	F5
Allocated Capacity (MW)	0	0	0	1

MARATHON DS		
Capacity = 4.3 MW		
	F2	F3
Allocated Capacity (MW)	0	0

MARGACH DS			
Capacity = 5.3 MW			
	F1	F2	F3
Allocated Capacity (MW)	0	3	0

MARIONVILLE DS		
Capacity = 15.7 MW		
	F1	F2
Allocated Capacity (MW)	10	0

MARTINDALE TS							
Capacity = 76.1 MW							
	M1	M2	M3	M4	M5	M6	M7
Allocated Capacity (MW)	0	0	0	10.1	10	27	28

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

MASSEY DS		
Capacity = 4 MW		
	F1	F3
Allocated Capacity (MW)	0	0

MAZINAW DS		
Capacity = 3.6 MW		
	F1	F2
Allocated Capacity (MW)	0	0

MEADOWVALE TS						
Capacity = 129.2 MW						
	M3	M4	M5	M6	M7	M8
Allocated Capacity (MW)	0	0	0	0	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

MEAFORD TS		
Capacity = 28.3 MW		
	M1	M2
Allocated Capacity (MW)	19	1.7

MIDHURST TS								
Capacity = 119.4 MW								
	M3	M4	M5	M6	M7	M8	M9	M10
Allocated Capacity (MW)	30	20	10	0	0	0	19.5	30

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

MILFORD DS	
Capacity = 1.6 MW	
	F2
Allocated Capacity (MW)	0.1

MILFORD DS is downstream of PICTON TS M5

MINAKI DS		
Capacity = 6.3 MW		
	F1	F2
Allocated Capacity (MW)	0	0

MINDEN TS				
Capacity = 42 MW				
Bus Capacity (MW)	T1 = 14.7		T2 = 27.4	
	M1	M3	M2	M4
Allocated Capacity (MW)	0	10.3	0	10

KINMOUNT DS is downstream of MINDEN TS M3

MODELAND TS
Capacity = Sum of Buses MW
For any information or inquiries please contact Blue Water Power Distribution Corporation

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

MOHAWK TS											
Capacity = Sum of Buses MW											
Bus Capacity (MW)	B = 4.6					Y = 5.4					
	M52	M53	M62	M63	M64	M71	M72	M73	M81	M82	M83
Allocated Capacity (MW)	0	0	0	0	0	0	0	0	0	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

MONTEITH DS		
Capacity = 6.7 MW		
	F1	F2
Allocated Capacity (MW)	0	0

MOOSE LAKE TS
Capacity = 5.7 MW
For any information or inquiries please contact Atikokan Hydro Inc.

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

MOOSONEE DS			
Capacity = 10.4 MW			
	F1	F2	F3
Allocated Capacity (MW)	0	0	0

MORRISBURG TS			
Capacity = 57.7 MW			
	M23	M25	M26
Allocated Capacity (MW)	14.7	30.8	20

MOUNTAIN CHUTE DS		
Capacity = 1.5 MW		
	F1	F2
Allocated Capacity (MW)	0	0

MURILLO DS								
Capacity = 0 MW								
Bus Capacity (MW)	T1 = 0				T2 = 0			
	F1	F3	F5	F7	F2	F4	F6	F8
Allocated Capacity (MW)	0	0	0	0	0	0	0	0

MURRAY TS DESN 1												
Capacity = Sum of Buses MW												
Bus Capacity (MW)	QZ = 5.4						Y1Y2 = 5.4					
	M51	M52	M53	M54	M55	M56	M25	M26	M27	M28	M29	M30
Allocated Capacity (MW)	0	0	0	0	0	0	0	0	0	0	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

MURRAY TS DESN 2								
Capacity = Sum of Buses MW								
Bus Capacity (MW)	J = 0.5			K = 5.4				
	M10	M11	M13	M14	M15	M16	M17	M18
Allocated Capacity (MW)	0	0	0	0	0	0	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

MUSKOKA TS									
Capacity = 70.4 MW									
	M1	M2	M3	M4	M5	M6	M7	M8	M9
Allocated Capacity (MW)	15	27.8	0	0	0	0	0	0	10

SUNDRIDGE NORTH DS is downstream of MUSKOKA TS M2

NAPANEE TS				
Capacity = 66.6 MW				
Bus Capacity (MW)	B T1 = 52.6		Y T2 = 54	
	M1	M3	M2	M4
Allocated Capacity (MW)	0	36.5	28.5	0

NAVAN DS				
Capacity = 4.1 MW				
	F1	F2	F3	F4
Allocated Capacity (MW)	0	0	0	0

NEBO TS DESN1						
Capacity = 62.9 MW						
	M3	M4	M5	M6	M7	M8
Allocated Capacity (MW)	0	0	13.2	0	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

NEBO TS DESN2								
Capacity = 5.4 MW								
	M51	M52	M53	M54	M61	M62	M63	M64
Allocated Capacity (MW)	0	0	0	0	0	0	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

NELSON TS DESN 1						
Capacity = 22.8 MW						
	M1	M2	M3	M4	M5	M6
Allocated Capacity (MW)	0	0	0	0	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

NELSON TS DESN 2												
Capacity = Sum of Buses MW												
Bus Capacity (MW)	PK = 5.4						YJ = 5.4					
	M31	M32	M33	M34	M35	M36	M11	M12	M13	M14	M15	M16
Allocated Capacity (MW)	0	0	0	0	0	0	0	0	0	0	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

NEPEAN TS
Capacity = 100.7 MW
For any information or inquiries please contact Ottawa Hydro Inc.

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

NESTOR FALLS DS		
Capacity = 2.1 MW		
	F1	F2
Allocated Capacity (MW)	0	0

NEWINGTON DS		
Capacity = 7.6 MW		
	F1	F2
Allocated Capacity (MW)	0	0

NEWTON TS										
Capacity = Sum of Buses MW										
Bus Capacity (MW)	B = 5.4					Y = 5.4				
	M1	M3	M6	M8	M10	M2	M4	M5	M7	M9
Allocated Capacity (MW)	0	0	0	0	0	0	0	0	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

NEWTONVILLE DS	
Capacity = 3.4 MW	
	F2
Allocated Capacity (MW)	2

NEWTONVILLE DS is downstream of PORT HOPE TS M18

NIPIGON DS		
Capacity = 2.3 MW		
	F1	F2
Allocated Capacity (MW)	0	0

NORFOLK TS						
Capacity = 55.9 MW						
	M1	M2	M3	M4	M5	M6
Allocated Capacity (MW)	0	10	18.4	0	17.5	10

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

NORTH BAY TS		
Capacity = 14.7 MW		
	M1	M3
Allocated Capacity (MW)	10	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

NORTH SHORE DS		
Capacity = 1.2 MW		
	F1	F2
Allocated Capacity (MW)	0	0

NORTHBROOK DS			
Capacity = 7.7 MW			
	F1	F2	F3
Allocated Capacity (MW)	0	0	0

NORTHCOTE DS	
Capacity = 4.2 MW	
	F3
Allocated Capacity (MW)	1.3

NORTHCOTE DS is downstream of COBDEN TS M2

OAKVILLE TS										
Capacity = Sum of Buses MW										
Bus Capacity (MW)	E = 10.8					Z = 10.8				
	M43	M45	M47	M49	M51	M44	M46	M48	M50	M52
Allocated Capacity (MW)	0	0	0	0	0	0	0	0	0	0

ORANGEVILLE TS 27 KV - DESN1				
Capacity = 53.1 MW				
	M23	M24	M25	M26
Allocated Capacity (MW)	10	10	9	10.5

ORANGEVILLE TS 44 KV - DESN1		
Capacity = 34 MW		
	M45	M46
Allocated Capacity (MW)	33.9	0

ORANGEVILLE TS DESN2						
Capacity = 67.8 MW						
	M1	M2	M3	M4	M5	M6
Allocated Capacity (MW)	0	25.4	0	27	0	0

ORILLIA TS								
Capacity = 87.6 MW								
	M1	M2	M3	M4	M5	M6	M7	M8
Allocated Capacity (MW)	1.1	29.8	10	30	0	10	0	0

OSGOODE DS	
Capacity = 11.1 MW	
	F4
Allocated Capacity (MW)	5

OSGOODE DS is downstream of HAWTHORNE TS M1

OTONABEE TS DESN 1				
Capacity = Sum of Buses MW				
Bus Capacity (MW)	J = 5		Q = 8.1	
	M8	M12	M9	M11
Allocated Capacity (MW)	0	0	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

OTONABEE TS DESN 2				
Capacity = Sum of Buses MW				
Bus Capacity (MW)	B = 5.9		Y = 5.6	
	M25	M27	M26	M28
Allocated Capacity (MW)	0	0	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

OVERBROOK TS
Capacity = Sum of Buses MW
For any information or inquiries please contact Hydro Ottawa

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

OWEN SOUND TS							
Capacity = 105.3 MW							
	M21	M22	M23	M24	M25	M26	M28
Allocated Capacity (MW)	19.8	9.9	0	14.1	29.1	29.7	0

SQUIRE DS is downstream of OWEN SOUND TS M25

PALERMO TS								
Capacity = 69.1 MW								
	M1	M2	M3	M4	M5	M6	M7	M8
Allocated Capacity (MW)	4	0	0	0	0	0	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

PALMERSTON TS				
Capacity = 55.8 MW				
	M1	M2	M3	M4
Allocated Capacity (MW)	17.8	30.5	0.1	0

KENILWORTH DS is downstream of PALMERSTON TS M2	ROTHSAY DS is downstream of PALMERSTON TS M2	TRALEE DS is downstream of PALMERSTON TS M3

PARRY SOUND TS				
Capacity = 36 MW				
	M1	M2	M3	M4
Allocated Capacity (MW)	18	0	18	0

PEMBROKE TS			
Capacity = 15.3 MW			
	M1	M2	M3
Allocated Capacity (MW)	0	9.9	0

PERRAULT FALLS DS		
Capacity = 0.6 MW		
	F1	F2
Allocated Capacity (MW)	0	0

PETAWAWA DS					
Capacity = 5.4 MW					
Bus Capacity (MW)	T1 = 5.1			T2 = 4.2	
	F1	F4	F5	F2	F3
Allocated Capacity (MW)	0	0	0	0	0

PIC DS		
Capacity = 8.3 MW		
	F1	F2
Allocated Capacity (MW)	0	0

PICTON DS	
Capacity = 3.4 MW	
	F2
Allocated Capacity (MW)	0

PICTON DS is downstream of PICTON TS M6

PICTON TS				
Capacity = 57.2 MW				
	M5	M6	M7	M8
Allocated Capacity (MW)	28	24	0	0

MILFORD DS is downstream of PICTON TS M5	PICTON DS is downstream of PICTON TS M6

PLANTAGENET DS	
Capacity = 4 MW	
	F2
Allocated Capacity (MW)	0.2

PLANTAGENET DS is downstream of LONGUEUIL TS M26

PLEASANT TS DESN 1								
Capacity = 100.9 MW								
	M21	M22	M23	M24	M25	M26	M27	M28
Allocated Capacity (MW)	0	0	10	0	0	10	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

PLEASANT TS DESN 2														
Capacity = Sum of Buses MW														
Bus Capacity (MW)	BY = 42.2								EZ = 56.7					
	M7	M8	M9	M10	M11	M12	M13	M14	M43	M44	M45	M46	M47	M48
Allocated Capacity (MW)	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

PLEASANT TS DESN 3												
Capacity = Sum of Buses MW												
Bus Capacity (MW)	F = 2.3						V = 3.2					
	M61	M63	M65	M67	M69	M71	M62	M64	M66	M68	M70	M72
Allocated Capacity (MW)	0	0	0	0	0	0	0	0	0	0	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

PORT ARTHUR TS #1							
Capacity = 10 MW							
	M2	M3	M4	M5	M6	M1	M27
Allocated Capacity (MW)	0	0	0	10	0	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

PORT BOLSTER DS	
Capacity = 3.5 MW	
	F2
Allocated Capacity (MW)	0.1

PORT BOLSTER DS is downstream of BEAVERTON TS M27

PORT COLBORNE TS				
Capacity = 33.7 MW				
	M9	M10	M11	M12
Allocated Capacity (MW)	0	0	12.8	19

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

PORT HOPE TS DESN 1				
Capacity = 50.2 MW				
	M15	M16	M17	M18
Allocated Capacity (MW)	0	34.9	0	11.9

NEWTONVILLE DS is downstream of PORT HOPE TS M18

PORT HOPE TS DESN 2				
Capacity = 67.2 MW				
	M1	M2	M3	M4
Allocated Capacity (MW)	0	0	0	10

PRESTON TS
Capacity = Sum of Buses MW
For any information or inquiries please contact Cambridge North Dumfries Hydro (CND)

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

PUSLINCH DS			
Capacity = 21 MW			
Bus Capacity (MW)	T1 = 15	T2 = 16.1	
	F1	F2	F4
Allocated Capacity (MW)	0	10	0

RAMORE TS		
Capacity = 8.6 MW		
	M3	M5
Allocated Capacity (MW)	0	0

RED LAKE TS			
Capacity = 40 MW			
	M3	M4	M6
Allocated Capacity (MW)	20	10	10

RED ROCK DS			
Capacity = 3.9 MW			
	F1	F2	F3
Allocated Capacity (MW)	0	0	0

REDDENDALE DS	
Capacity = 3.2 MW	
	F3
Allocated Capacity (MW)	0.5

REDDENDALE DS is downstream of KINGSTON GARDINER TS M11

REID CORNERS DS	
Capacity = 2 MW	
	F1
Allocated Capacity (MW)	0.3

REID CORNERS DS is downstream of DOUGLAS POINT TS M6

REXDALE TS												
Capacity = Sum of Buses MW												
Bus Capacity (MW)	BY = 53.9						QJ = 47.8					
	M31	M32	M33	M34	M35	M36	M1	M2	M3	M4	M5	M6
Allocated Capacity (MW)	0	0	0	0	0	0	0	0	0	0	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

RICHMOND DS			
Capacity = 4.2 MW			
	F1	F2	F3
Allocated Capacity (MW)	0	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

RICHVIEW TS DESN 1								
Capacity = Sum of Buses MW								
Bus Capacity (MW)	J = 10.8				E = 10.8			
	M12	M14	M16	M18	M11	M13	M15	M17
Allocated Capacity (MW)	0	0	0	0	0	0	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

RICHVIEW TS DESN 2								
Capacity = 89.9 MW								
Bus Capacity (MW)	Q = 48.8				Z = 41.1			
	M41	M43	M45	M47	M42	M44	M46	M48
Allocated Capacity (MW)	0	0	0	0	0	0	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

RICHVIEW TS DESN 3								
Capacity = 64.2 MW								
	M1	M2	M3	M4	M5	M6	M7	M8
Allocated Capacity (MW)	0	0	0	0	0	0	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

RIVERDALE TS
Capacity = Sum of Buses MW
For any information or inquiries please contact Hydro Ottawa

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

ROCKLAND DS			
Capacity = 7.9 MW			
	F1	F2	F3
Allocated Capacity (MW)	0	0	0

ROCKLAND EAST DS				
Capacity = 7.4 MW				
Bus Capacity (MW)	T1 = 5.7			T2 = 6.4
	F4	F5	F6	F1
Allocated Capacity (MW)	0	0	0	0

ROTHSAY DS	
Capacity = 3.7 MW	
	F3
Allocated Capacity (MW)	0.3

ROTHSAY DS is downstream of PALMERSTON TS M2

RUNNYMEDE TS								
Capacity = 75.1 MW								
	M1	M2	M3	M4	M5	M6	M7	M8
Allocated Capacity (MW)	0	0	0	0	0	0	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

RUSSELL DS				
Capacity = 1.8 MW				
	F1	F2	F3	F4
Allocated Capacity (MW)	0	0	0	0

RUSSELL TS
Capacity = Sum of Buses MW
For any information or inquiries please contact Hydro Ottawa

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

SAM LAKE DS				
Capacity = 18.2 MW				
	F1	F2	F3	F4
Allocated Capacity (MW)	0	0	0	0

SAPAWE DS		
Capacity = 1.7 MW		
	F1	F2
Allocated Capacity (MW)	0	0

SCARBORO TS - DESN1												
Capacity = Sum of Buses MW												
Bus Capacity (MW)	J = 10.8						Q = 10.8					
	M21	M23	M25	M27	M29	M31	M22	M24	M26	M28	M30	M32
Allocated Capacity (MW)	0	0	0	0	0	0	0	0	0	0	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

SCARBORO TS - DESN2										
Capacity = Sum of Buses MW										
Bus Capacity (MW)	B = 3.6					Y = 10.8				
	M1	M3	M5	M7	M9	M2	M4	M6	M8	M10
Allocated Capacity (MW)	0	0	0	0	0	0	0	0	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

SCHOMBERG DS		
Capacity = 9.3 MW		
	F2	F3
Allocated Capacity (MW)	0	0.1

SCHOMBERG DS is downstream of KLEINBURG TS M24

SCHREIBER WINNIPG DS		
Capacity = 4 MW		
	F1	F2
Allocated Capacity (MW)	0	0

SEAFORTH TS				
Capacity = 33 MW				
	M2	M3	M4	M5
Allocated Capacity (MW)	10	0	19.9	0

SHABAQUA DS				
Capacity = 3.7 MW				
Bus Capacity (MW)	M2, F1, F2 = 3.7			F1, F2 = N/A
	M2	F1	F2	M2
Allocated Capacity (MW)	0	2.4	0	0

SHARBOT DS			
Capacity = 3.8 MW			
	F1	F2	F3
Allocated Capacity (MW)	0	0	0

SHEPPARD TS DESN 1
Capacity = 69.5 MW
For any information or inquiries please contact Toronto Hydro

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

SHEPPARD TS DESN 2
Capacity = 72.5 MW
For any information or inquiries please contact Toronto Hydro

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

SHININGTREE DS	
Capacity = 2.2 MW	
	M1
Allocated Capacity (MW)	0

SIDNEY TS						
Capacity = 37 MW						
	M1	M3	M4	M5	M6	M7
Allocated Capacity (MW)	0	0	10	0	0	19.8

SIOUX NARROWS DS		
Capacity = 1.4 MW		
	F1	F2
Allocated Capacity (MW)	0	0

SLATE FALLS DS	
Capacity = 1.5 MW	
	F1
Allocated Capacity (MW)	0

SLATER TS
Capacity = Sum of Buses MW
For any information or inquiries please contact Hydro Ottawa

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

SMITHS FALLS TS								
Capacity = 88.4 MW								
	M21	M22	M23	M24	M25	M26	M27	M28
Allocated Capacity (MW)	0	30	30	0	20	0	0	0

SMOOTH ROCK FALLS DS		
Capacity = 6.8 MW		
Bus Capacity (MW)	T1 = 6.5	T2 = 6.3
	F1	F2
Allocated Capacity (MW)	0	0

SOUTH GLOUCESTER DS		
Capacity = 4 MW		
	F1	F2
Allocated Capacity (MW)	0	0

SOUTH MARCH TS						
Capacity = 67.9 MW						
	M1	M2	M3	M4	M5	M6
Allocated Capacity (MW)	0	0	10	0	21.9	30

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

ALEXANDER DS is downstream of SOUTH MARCH TS M5

SOWERBY DS		
Capacity = 3.7 MW		
	F1	F2
Allocated Capacity (MW)	0	0

SPANISH DS		
Capacity = 7.4 MW		
	F1	F2
Allocated Capacity (MW)	0	0

SPENCERVILLE DS	
Capacity = 1.3 MW	
	F2
Allocated Capacity (MW)	0.5

SPENCERVILLE DS is downstream of BROCKVILLE TS B1R

SPRINGVALE DS	
Capacity = 6.8 MW	
	F1
Allocated Capacity (MW)	0

SPRINGVALE DS is downstream of FOREST JURA DS F1

SQUIRE DS	
Capacity = 3.6 MW	
	F3
Allocated Capacity (MW)	0.1

SQUIRE DS is downstream of OWEN SOUND TS M25

ST ANDREWS TS
Capacity = 81.9 MW
For any information or inquiries please contact Blue Water Power Distribution Corporation

ST ISIDORE TS				
Capacity = 33.9 MW				
	M1	M2	M3	M4
Allocated Capacity (MW)	10.5	14.3	0	7.5

CRYSLER DS is downstream of ST ISIDORE TS M2

GLENGARRY DS is downstream of ST ISIDORE TS M4

ST LAWRENCE TS					
Capacity = 72.7 MW					
	M24	M25	M26	M27	M28
Allocated Capacity (MW)	0	10	29.7	0	0

ST MARYS TS						
Capacity = 28.9 MW						
	M1	M2	M3	M4	M5	M6
Allocated Capacity (MW)	0	0	0	0	10	0

ST THOMAS TS DESN 1	
Capacity = 15.9 MW	
	M10
Allocated Capacity (MW)	10

ST THOMAS TS DESN 2

Capacity = 21.7 MW

	M3	M5
Allocated Capacity (MW)	0	0

STANLEY TS

Capacity = Sum of Buses MW

Bus Capacity (MW)	QJ = 5.4						BY = 5.4					
	M31	M32	M33	M41	M42	M43	M1	M2	M3	M4	M5	M6
Allocated Capacity (MW)	0	0	0	0	0	0	0	0	0	0	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

STARDALE DS

Capacity = 3.8 MW

	F2	F3
Allocated Capacity (MW)	0.3	0.6

STARDALE DS is downstream of LONGUEUIL TS M23

STAYNER TS

Capacity = 89.7 MW

	M1	M2	M3	M4	M5	M6	M7	M8
Allocated Capacity (MW)	10	38	0	30	0	0	0	0

STEWARTVILLE TS

Capacity = 21.4 MW

	M1	M3	M4
Allocated Capacity (MW)	0	20	0

STIRLING DS

Capacity = 4 MW

	F3
Allocated Capacity (MW)	0.5

STIRLING DS is downstream of BELLEVILLE TS M5

STIRTON TS

Capacity = Sum of Buses MW

Bus Capacity (MW)	BY = 10.8										QZ = 1.1							
	M71	M72	M75	M76	M81	M82	M83	M84	M85	M86	M51	M52	M53	M54	M61	M62	M63	M64
Allocated Capacity (MW)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

STRACHAN TS DESN 1

Capacity = Sum of Buses MW

For any information or inquiries please contact Toronto Hydro

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

STRACHAN TS DESN 2

Capacity = Sum of Buses MW

For any information or inquiries please contact Toronto Hydro

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

STRATFORD TS

Capacity = 75.9 MW

	M1	M2	M3	M4	M5	M6	M7	M8
Allocated Capacity (MW)	0	0	0	0	0	20	20	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

STRATHROY TS

Capacity = 34.3 MW

	M1	M2	M3	M4
Allocated Capacity (MW)	20	0	9	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

STRIKER DS

Capacity = 10.6 MW

Bus Capacity (MW)	T1 = 7.9	T2 = 7.9
	F1	F2
Allocated Capacity (MW)	0	0

SUNDRIDGE NORTH DS

Capacity = 4.6 MW

	F2
Allocated Capacity (MW)	0.8

SUNDRIDGE NORTH DS is downstream of MUSKOKA TS M2

TALBOT TS DESN 1

Capacity = 61.3 MW

	M11	M12	M13	M14	M21	M22	M23	M25
Allocated Capacity (MW)	0	0	0	0	0	0	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

TALBOT TS DESN 2

Capacity = Sum of Buses MW

Bus Capacity (MW)	J1J2 = 10.8						Q1Q2 = 10.8					
	M41	M42	M43	M46	M47	M48	M51	M52	M53	M54	M55	M56
Allocated Capacity (MW)	0	0	0	0	0	0	0	0	0	0	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

TEMAGAMI DS

Capacity = 3.3 MW

	F1	F2
Allocated Capacity (MW)	0	0

TERAULEY TS DESN 1

Capacity = Sum of Buses MW

For any information or inquiries please contact Toronto Hydro

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

TERAULEY TS DESN 2

Capacity = Sum of Buses MW

For any information or inquiries please contact Toronto Hydro

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

THORNTON TS

Capacity = 98.2 MW

	M1	M2	M3	M4	M5	M6	M7	M8
Allocated Capacity (MW)	0	0	2	0	0	0	0	10

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

THOROLD TS

Capacity = Sum of Buses MW

	M1	M2	M3
Allocated Capacity (MW)	0	0	0

TILBURY TS

Capacity = 5 MW

	M1
Allocated Capacity (MW)	5

TILBURY WEST DS

Capacity = 18.4 MW

Bus Capacity (MW)	T1 = 14.3	T2 = 15.2
	F1	F2
Allocated Capacity (MW)	0.5	10

TILLSONBURG DS	
Capacity = 2.7 MW	
	F2
Allocated Capacity (MW)	0.1

TILLSONBURG DS is downstream of TILLSONBURG TS M2

TILLSONBURG TS								
Capacity = 66.2 MW								
	M1	M2	M3	M4	M5	M6	M7	M10
Allocated Capacity (MW)	0	19.9	10	19.9	0	0	0	9.9

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

TILLSONBURG DS is downstream of TILLSONBURG TS M2

TIMMINS TS							
Capacity = 58.5 MW							
	M5	M6	M7	M8	M9	M10	M11
Allocated Capacity (MW)	0	0	15.5	15	0	0	16

TOMKEN TS DESN1								
Capacity = 101.2 MW								
	M1	M2	M3	M4	M5	M6	M7	M8
Allocated Capacity (MW)	0	0	0	0	0	0	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

TOMKEN TS DESN2								
Capacity = 102.6 MW								
	M23	M24	M25	M26	M27	M28	M29	M30
Allocated Capacity (MW)	0	0	0	0	0	0	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

TRAFALGAR TS					
Capacity = 63.1 MW					
	M4	M5	M6	M7	M8
Allocated Capacity (MW)	0	0	0	0	0

TRALEE DS	
Capacity = 4 MW	
	F3
Allocated Capacity (MW)	0.2

TRALEE DS is downstream of PALMERSTON TS M3

TROUT CREEK DS	
Capacity = 4.5 MW	
	F1
Allocated Capacity (MW)	0.8

TROUT CREEK DS is downstream of TROUT LAKE TS M7

TROUT LAKE TS								
Capacity = 89.4 MW								
	M1	M2	M3	M4	M5	M6	M7	M8
Allocated Capacity (MW)	0	0	27	0	10.6	0	20.8	30

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

TROUT CREEK DS is downstream of TROUT LAKE TS M7

VALORA DS	
Capacity = 1.6 MW	
	F1
Allocated Capacity (MW)	0

VANSICKLE TS
Capacity = 17.1 MW
For any information or inquiries please contact Horizon Utilities Corporation

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

VERMILION BAY DS			
Capacity = 3.9 MW			
	F1	F2	F3
Allocated Capacity (MW)	0	0	0

VERNER DS			
Capacity = 6 MW			
	F1	F2	F3
Allocated Capacity (MW)	0	0	0

VINELAND DS
Capacity = 14.4 MW
For any information or inquiries please contact Niagara Peninsula Energy Inc.

WALKER TS #1
Capacity = 59.4 MW
For any information or inquiries please contact EnWin Utilities

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

WALLACE TS			
Capacity = 31.2 MW			
Bus Capacity (MW)	T3 = 23.5	T4 = 31.2	
	M1	M4	M6
Allocated Capacity (MW)	0.6	0	27

WALLACEBURG TS					
Capacity = 35.8 MW					
	M1	M2	M3	M5	M6
Allocated Capacity (MW)	9.9	0	20.5	0	0

WANSTEAD TS				
Capacity = 33.2 MW				
Bus Capacity (MW)	T1T2 = 23.7		T3 = 33.2	
	M2	M4	M1	M3
Allocated Capacity (MW)	0	0	20	4.8

WARDEN TS											
Capacity = Sum of Buses MW											
Bus Capacity (MW)	J = 46.2						Q = 47				
	M21	M23	M25	M27	M29	M31	M24	M26	M28	M30	M32
Allocated Capacity (MW)	0	0	0	0	0	0	0	0	0	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

WARREN DS				
Capacity = 5.7 MW				
Bus Capacity (MW)	T1 = 4.6		T2 = 5.2	
	F1	F2	F3	F4
Allocated Capacity (MW)	0	0	0	0

WAUBAUSHENE TS							
Capacity = 57.3 MW							
	M1	M2	M3	M4	M5	M6	M7
Allocated Capacity (MW)	0	0	0	0	20	0	28

WENDOVER DS		
Capacity = 15.5 MW		
Bus Capacity (MW)	T1 = 13.9	T2 = 15
	F1	F3
Allocated Capacity (MW)	2.2	11.3

WESTON LAKE DS		
Capacity = 6.7 MW		
	F1	F2
Allocated Capacity (MW)	0	0

WHARNCLIFFE DS		
Capacity = 3.7 MW		
	F1	F2
Allocated Capacity (MW)	0	0.1

WHITBY TS - 27.6 kV DESN1 (T1&T2) - BY						
Capacity = 10.8 MW						
	M43	M44	M45	M46	M47	M48
Allocated Capacity (MW)	0	0	0	0	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

WHITBY TS - 44 kV DESN1 (T1&T2) - EZ				
Capacity = 10.8 MW				
	M5	M6	M7	M8
Allocated Capacity (MW)	0	0	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

WHITBY TS - 44kV DESN2 (T3&T4)								
Capacity = 110 MW								
	M21	M22	M23	M24	M25	M26	M27	M28
Allocated Capacity (MW)	0.5	0	18.8	9.9	0	0	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

WHITE RIVER DS			
Capacity = 4.2 MW			
	F1	F2	F3
Allocated Capacity (MW)	0	0	0

WHITEFISH DS		
Capacity = 4.8 MW		
	F1	F2
Allocated Capacity (MW)	0	0

WILHAVEN DS					
Capacity = 24.9 MW					
Bus Capacity (MW)	T1 = 20.4			T2 = 20.8	
	F1	F2	F3	F4	F5
Allocated Capacity (MW)	0	0	10	0	0

WILSON TS DESN 1								
Capacity = 109.7 MW								
	M1	M2	M3	M4	M5	M6	M7	M8
Allocated Capacity (MW)	2.5	0	0	0	0	0	0	20

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

WILSON TS DESN 2								
Capacity = 106.3 MW								
	M11	M12	M13	M14	M15	M16	M17	M18
Allocated Capacity (MW)	0	30	29.9	10	0	0	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

WILTSHIRE TS DESN 1
Capacity = 52.5 MW
For any information or inquiries please contact Toronto Hydro

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

WINDSOR MALDEN TS												
Capacity = Sum of Buses MW												
Bus Capacity (MW)	B = 40						Y = 50					
	M1	M3	M5	M7	M9	M11	M2	M4	M6	M8	M10	M12
Allocated Capacity (MW)	0	0	0	20.4	0	19.8	0	0	0	9.9	19.8	19.9

WINGHAM TS				
Capacity = 56.8 MW				
	M3	M4	M5	M6
Allocated Capacity (MW)	28	0	10	18

WINONA TS
Capacity = 50.9 MW
For any information or inquiries please contact Horizon Utilities Corporation

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

WOLVERTON DS		
Capacity = 18.5 MW		
Bus Capacity (MW)	T1 = 15.3	T2 = 15.2
	F1	F2
Allocated Capacity (MW)	9.9	0

WONDERLAND TS								
Capacity = 68.3 MW								
	M1	M2	M3	M4	M5	M6	M7	M8
Allocated Capacity (MW)	7.1	20	0	0	0	0	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

WOODBRIDGE TS										
Capacity = Sum of Buses MW										
	M1	M2	M3	M4	M5	M6	M12	M13	M15	M16
Allocated Capacity (MW)	0	0	0	0	0	0	0	0	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

WOODBRIDGE TS 27.6						
Capacity = 10.8 MW						
	M1	M2	M3	M4	M5	M6
Allocated Capacity (MW)	0	0	0	0	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

WOODBRIDGE TS 44 kV				
Capacity = 0 MW				
	M12	M13	M15	M16
Allocated Capacity (MW)	0	0	0	0

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

WOODBRIDGE TS 44 kV
Capacity = 0 MW
For any information or inquiries please contact Hydro Ottawa

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

WOODSTOCK TS							
Capacity = 68.9 MW							
	M3	M4	M6	M7	M8	M9	M10
Allocated Capacity (MW)	0	10	20	0	0	19.4	9

Station may supply another LDC's territory. Refer to OPA FIT LDC locator tool to find LDC.

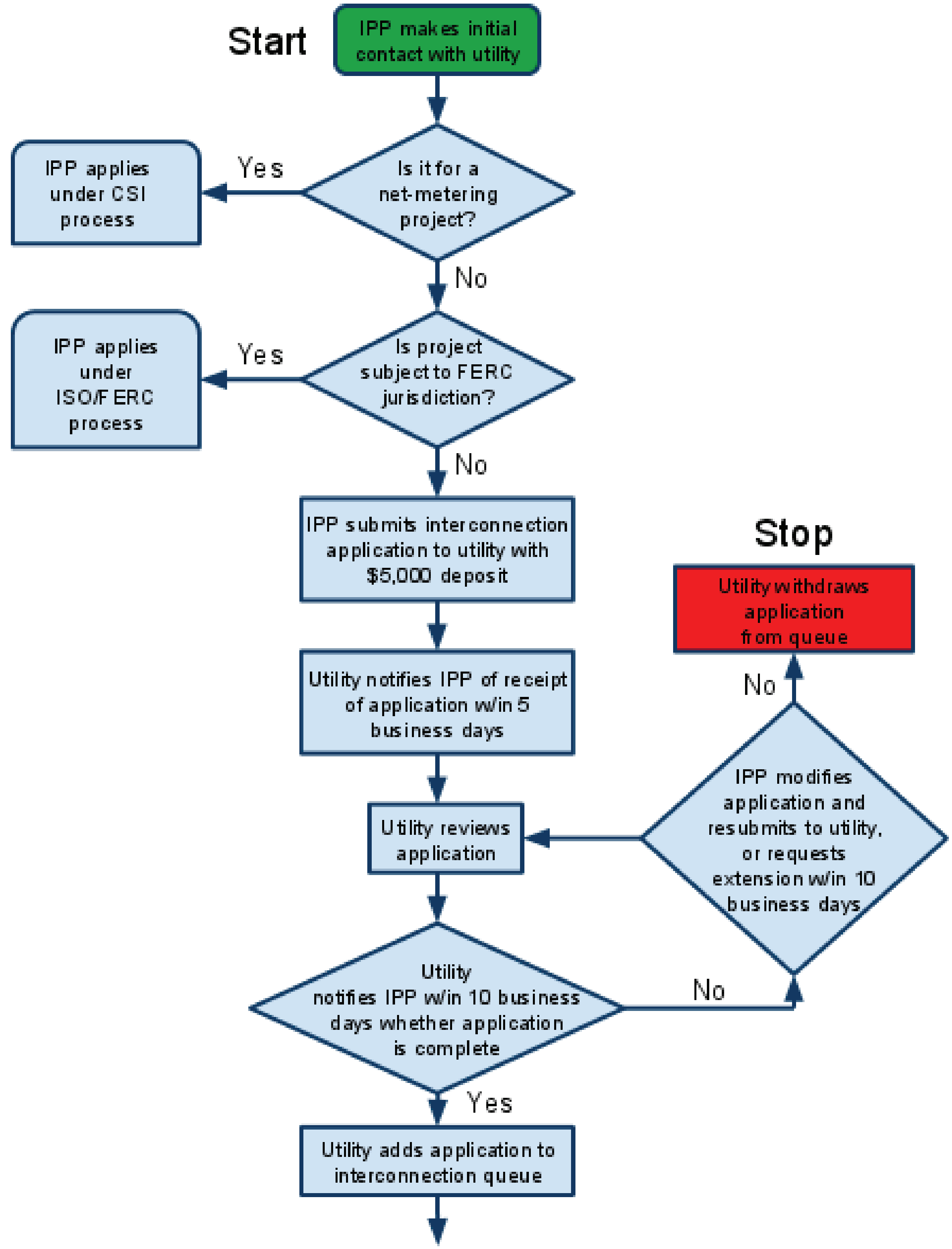
WOODSTOCK ZORRA DS is downstream of WOODSTOCK TS M9

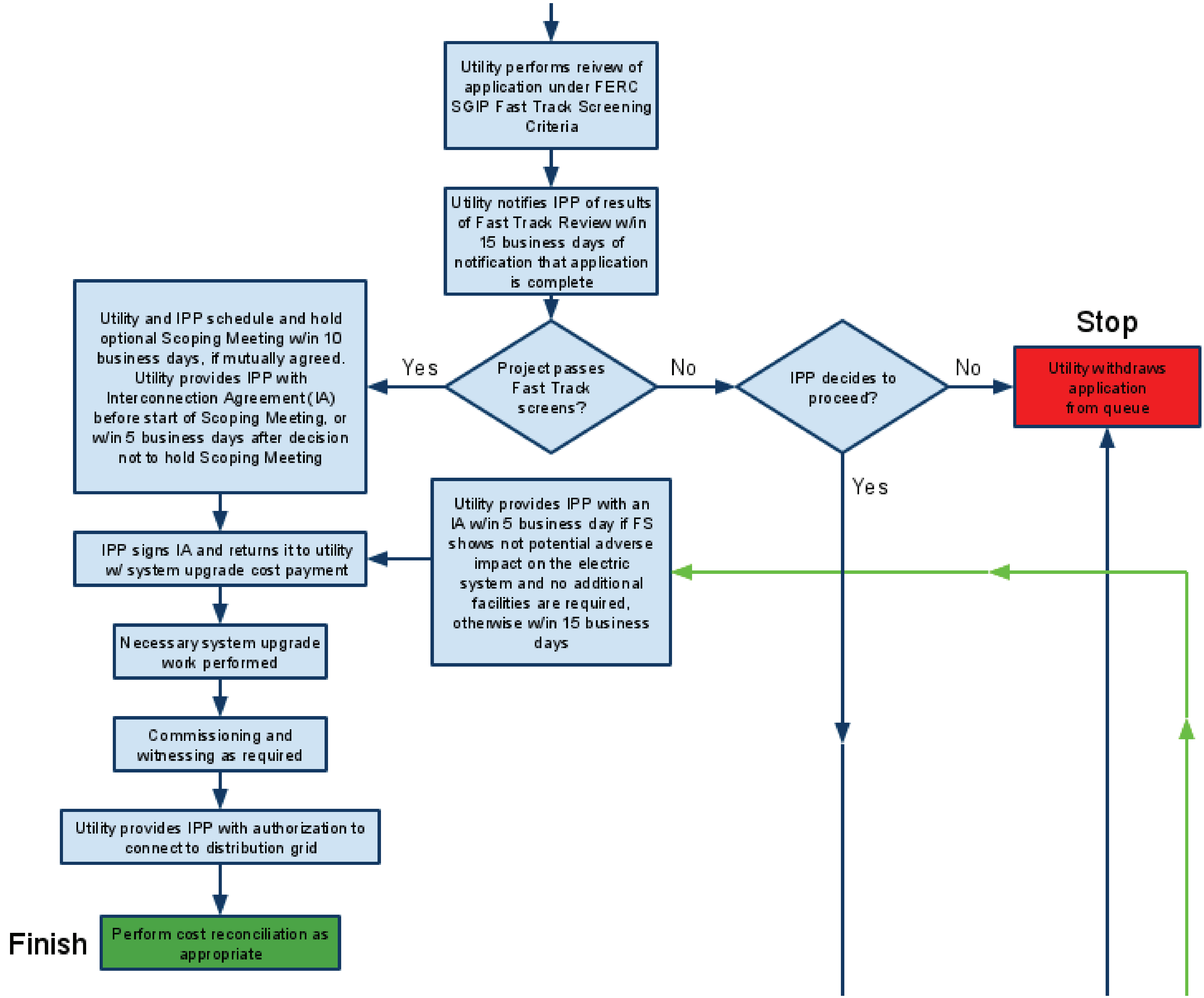
WOODSTOCK ZORRA DS	
Capacity = 3.9 MW	
	F2
Allocated Capacity (MW)	0.1

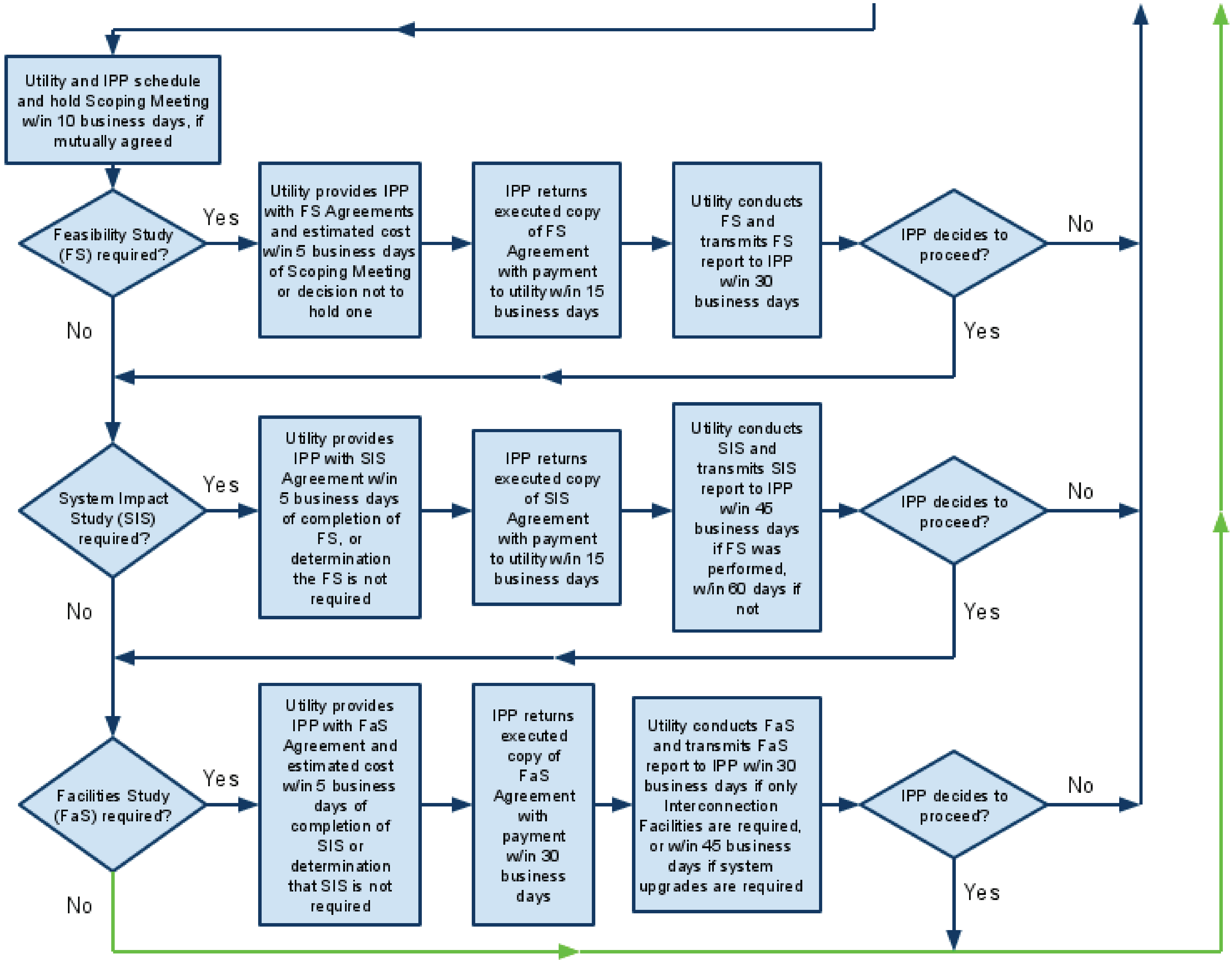
WOODSTOCK ZORRA DS is downstream of WOODSTOCK TS M9

Appendix C

Distributed Generation Feed-In Tariff Interconnection Process Flow Chart


Start
IPP makes initial contact with utility
Is it for a net-metering project?
Yes
IPP applies under CSI process
No
Is project subject to FERC jurisdiction?
Yes
IPP applies under ISO/FERC process
No
IPP submits interconnection application to utility with $5,000 deposit
Utility notifies IPP of receipt of application w/in 5 business days
Utility reviews application
Utility notifies IPP w/in 10 business days whether application is complete
Yes
Utility adds application to interconnection queue
No
IPP modifies application and resubmits to utility, or requests extension w/in 10 business days
No
Stop
Utility withdraws application from queue


Utility performs reivew of application under FERC SGIP Fast Track Screening Criteria
Utility notifies IPP of results of Fast Track Review w/in 15 business days of notification that application is complete
Project passes Fast Track screens?
Yes
No
IPP decides to proceed?
No
Yes
Stop
Utility withdraws application from queue
Utility and IPP schedule and hold optional Scoping Meeting w/in 10 business days, if mutually agreed. Utility provides IPP with Interconnection Agreement (IA) before start of Scoping Meeting, or w/in 5 business days after decision not to hold Scoping Meeting
Utility provides IPP with an IA w/in 5 business day if FS shows not potential adverse impact on the electric system and no additional facilities are required, otherwise w/in 15 business days
IPP signs IA and returns it to utility w/ system upgrade cost payment
Necessary system upgrade work performed
Commissioning and witnessing as required
Utility provides IPP with authorization to connect to distribution grid
Finish
Perform cost reconciliation as appropriate


Utility and IPP schedule and hold Scoping Meeting w/in 10 business days, if mutually agreed
Feasibility Study (FS) required?
Yes
No
Utility provides IPP with FS Agreements and estimated cost w/in 5 business days of Scoping Meeting or decision not to hold one
IPP returns executed copy of FS Agreement with payment to utility w/in 15 business days
Utility conducts FS and transmits FS report to IPP w/in 30 business days
IPP decides to proceed?
No
Yes
System Impact Study (SIS) required?
Yes
No
Utility provides IPP with SIS Agreement w/in 5 business days of completion of FS, or determination the FS is not required
IPP returns executed copy of SIS Agreement with payment to utility w/in 15 business days
Utility conducts SIS and transmits SIS report to IPP w/in 45 business days if FS was performed, w/in 60 days if not
IPP decides to proceed?
No
Yes
Facilities Study (FaS) required?
Yes
No
Utility provides IPP with FaS Agreement and estimated cost w/in 5 business days of completion of SIS or determination that SIS is not required
IPP returns executed copy of FaS Agreement with payment w/in 30 business days
Utility conducts FaS and transmits FaS report to IPP w/in 30 business days if only Interconnection Facilities are required, or w/in 45 business days if system upgrades are required
IPP decides to proceed?
No
Yes

Appendix D

Sample IOU Interconnection Data Report

Name of IOU: Sample G&E
Date: 10/19/2009 12:29

Station Name	Distribution Circuit / Bus Name	Total Capacity (MW)	Allocated Capacity (MW)	Queued Capacity (MW)	Available Capacity (MW)	Supply Circuit Name	Availability (MW)
Amador TS	Total	50	19	3	28	C4R	50
Amador TS	A5A6	25	7	0	18	C4R	50
Amador TS	A7A8	25	12	3	10	C4R	50
Irvine DS	Total	8	4	0	4	M6E	50
McCloud TS DESN1	Total	84	43	5	36	I17J	120
McCloud TS DESN1	B	41	28	3	10	I17J	120
McCloud TS DESN1	Y	43	15	2	26	I17J	120
Ridge DS	Total	10	5	1	3	L4V	60
Ridge DS	T1	4	2	1	1	L4V	60
Ridge DS	T2	5	3	0	2	L4V	60

Appendix E

PUC FIT Program

Auction Capacity Apportionment Process

Prior year's electricity usage in northern CA region:	50,000	**GW**		21.74%
Prior year's electricity usage in central CA region:	60,000	**GW**		26.09%
Prior year's electricity usage in southern CA region:	120,000	**GW**		52.17%
Total prior year's electricity usage in California:	**230,000**	**GW**		**100.00%**
Single Auction Capacity Target:	**500**	**MW**		
Northern Region Total Auction Capacity:	**109**	**MW**	**=**	500 X 21.74%
Northern Region Project Size Range Capacities:				
100 kW to 1 MW	22	MW		20%
1 MW to 5 MW	33	MW		30%
5 MW to 10 MW	54	MW		50%
Total	**109**	**MW**		**100%**
Central Region Total Auction Capacity:	**130**	**MW**	**=**	500 X 26.09%
Central Region Project Size Range Capacities:				
100 kW to 1 MW	26	MW		20%
1 MW to 5 MW	39	MW		30%
5 MW to 10 MW	65	MW		50%
Total	**130**	**MW**		**100%**
Southern Region Total Auction Capacity:	**261**	**MW**	**=**	500 X 52.17%
Southern Region Project Size Range Capacities:				
100 kW to 1 MW	52	MW		20%
1 MW to 5 MW	78	MW		30%
5 MW to 10 MW	130	MW		50%
Total	**261**	**MW**		**100%**

SERVICE LIST: R.08-08-009

ab1@cpuc.ca.gov	jwright@semprautilities.com
abb@eslawfirm.com	kar@cpuc.ca.gov
abiecunasjp@bv.com	karen@klindh.com
abrowning@votesolar.org	karly@solardevelop.com
aeg@cpuc.ca.gov	kdusel@navigantconsulting.com
aes@cpuc.ca.gov	keith.mccrea@sablaw.com
alex.kang@itron.com	keithwhite@earthlink.net
amber@iepa.com	kelly.cauvel@build-laccd.org
ams@cpuc.ca.gov	ken.alex@doj.ca.gov
amsmith@sempra.com	kenneth.swain@navigantconsulting.com
andy.vanhorn@vhcenergy.com	kerry.eden@ci.corona.ca.us
arno@recurrentenergy.com	kerry.hattevik@nrgenergy.com
artrivera@comcast.net	kfox@keyesandfox.com
as2@cpuc.ca.gov	khassan@sempra.com
atrowbridge@daycartermurphy.com	kjsimonsen@ems-ca.com
Audra.Hartmann@Dynegy.com	klatt@energyattorney.com
bari@pge.com	kmills@cfbf.com
bbaker@summitblue.com	kowalewskia@calpine.com
bcragg@goodinmacbride.com	kswitzer@gswater.com
bdicapo@caiso.com	kswitzer@gswater.com
bepstein@fablaw.com	kwh@cpuc.ca.gov
bernardo@braunlegal.com	kyle.l.davis@pacificorp.com
beth@beth411.com	kzocchet@energy.state.ca.us
bill@fitcoalition.com	lau@cpuc.ca.gov
blaising@braunlegal.com	leichnitz@lumospower.com
bobgex@dwt.com	lfavret@3degreesinc.com
boudreauxk@calpine.com	lgonzale@energy.state.ca.us
brbarkovich@earthlink.net	liddell@energyattorney.com
bruce.foster@sce.com	llund@commerceenergy.com
bsb@eslawfirm.com	lmh@eslawfirm.com
bwm@cpuc.ca.gov	lpark@navigantconsulting.com
c.mentzel@cleanenergymaui.com	LPaskett@Firstsolar.com
cadowney@cadowneylaw.com	lterry@water.ca.gov
californiadockets@pacificorp.com	lwisland@ucsusa.org
case.admin@sce.com	lynn@lmaconsulting.com
castille@landsenergy.com	m.stout@cleantechamerica.com
cathy.karlstad@sce.com	marcel@turn.org
cec@cpuc.ca.gov	marcie.milner@shell.com
cem@newsdata.com	Marla.Dickerson@latimes.com
cem@newsdata.com	martinhomec@gmail.com
CentralFiles@semprautilities.com	martinhomec@gmail.com
chad@cenergypower.com	mary@solutionsforutilities.com
Christine@consciousventuresgroup.com	masont@bv.com
ciw@cpuc.ca.gov	matthew@turn.org
ckebler@SempraGeneration.com	mc3@cpuc.ca.gov
claufenb@energy.state.ca.us	mcarboy@signalhill.com

cleni@energy.state.ca.us	mchediak@bloomberg.net
cleni@energy.state.ca.us	mclaughlin@braunlegal.com
clyde.murley@comcast.net	mcmahon@solarmillennium.com
cmkehrein@ems-ca.com	mday@goodinmacbride.com
cmmw@pge.com	mdeange@smud.org
cnl@cpuc.ca.gov	mdjoseph@adamsbroadwell.com
cpechman@powereconomics.com	mgarcia@arb.ca.gov
cponds@ci.chula-vista.ca.us	mhyams@sfwater.org
cpuccases@pge.com	michaelboyd@sbcglobal.net
cpucdockets@keyesandfox.com	michaelgilmore@inlandenergy.com
cpucrulings@navigantconsulting.com	mike.montoya@sce.com
craig.lewis@greenvolts.com	mjd@cpuc.ca.gov
crmd@pge.com	mjh@cpuc.ca.gov
css@cpuc.ca.gov	mjs@cpuc.ca.gov
csteen@bakerlaw.com	mmazur@3PhasesRenewables.com
cswoollums@midamerican.com	MMCL@pge.com
ctd@cpuc.ca.gov	mniroula@water.ca.gov
cte@eslawfirm.com	MoniqueStevenson@SeaBreezePower.com
ctorchia@chadbourne.com	mpa@a-klaw.com
cwooten@lumenxconsulting.com	mpo@cpuc.ca.gov
Cynthia.A.Fonner@constellation.com	mpr-ca@coolearthsolar.com
Dan.adler@calcef.org	mpryor@energy.state.ca.us
danielle@ceert.org	mramirez@sfwater.org
david.oliver@navigantconsulting.com	mrh2@pge.com
davidb@cwo.com	mrl@cpuc.ca.gov
davido@mid.org	mrw@mrwassoc.com
dbp@cpuc.ca.gov	mwt@cpuc.ca.gov
dcarroll@downeybrand.com	nao@cpuc.ca.gov
dcover@esassoc.com	ndesnoo@ci.berkeley.ca.us
demorse@omsoft.com	nellie.tong@us.kema.com
dennis@ddecuir.com	nes@a-klaw.com
derek@evomarkets.com	NFranklin@edisonmission.com
dgeis@dolphingroup.org	Nick.Allen@morganstanley.com
dgrandy@caonsitegen.com	nick.chaset@tesserasolar.com
dgulino@ridgewoodpower.com	nicole.fabri@clearenergybrokerage.com
dhuard@manatt.com	nil@cpuc.ca.gov
Diane.Fellman@nexteraenergy.com	nlr@cpuc.ca.gov
dietrichlaw2@earthlink.net	norman.furuta@navy.mil
dkk@eslawfirm.com	npedersen@hanmor.com
dniehaus@semprautilities.com	nrader@calwea.org
DocToxics@aol.com	nsuetake@turn.org
dorth@krcd.org	nxk2@pge.com
dot@cpuc.ca.gov	paulfenn@local.org
Douglas@Idealab.com	pdoughma@energy.state.ca.us
douglass@energyattorney.com	pepper@cleanpowermarkets.com
dsaul@pacificsolar.net	peter.pearson@bves.com
dseperas@calpine.com	pfmoritzburke@gmail.com
dsh@cpuc.ca.gov	phanschen@mofo.com
dtownley@infiniacorp.com	phil@reesechambers.com
dvidaver@energy.state.ca.us	pletkarj@bv.com

dws@r-c-s-inc.com	pmaxwell@navigantconsulting.com
echiang@elementmarkets.com	porter@exeterassociates.com
ecl8@pge.com	psd@cpuc.ca.gov
ed.mainland@sierraclub.org	pshaw@suntechamerica.com
ed.smeloff@sunpowercorp.com	pssed@adelphia.net
edwardoneill@dwt.com	pstoner@lgc.org
EGrizard@deweysquare.com	ralf1241a@cs.com
eisenblh@email.laccd.edu	ramonag@ebmud.com
ej_wright@oxy.com	rblee@bakerlaw.com
ek@a-klaw.com	rbuckenham@calbioenergy.com
eks@cpuc.ca.gov	RegRelCPUCCases@pge.com
elaine.duncan@verizon.com	renee@gem-corp.com
ELL5@pge.com	rhassan@fbr.com
elvine@lbl.gov	richard.chandler@bp.com
email@semprasolutions.com	rick@sierraecos.com
emello@sppc.com	rick_noger@praxair.com
e-recipient@caiso.com	rjgilleskie@san.rr.com
eric.cherniss@gmail.com	rkeen@manatt.com
evk1@pge.com	rkmoore@gswater.com
farrellytc@earthlink.net	rkn@cpuc.ca.gov
fhall@solarelectricsolutions.com	rliebert@cfbf.com
filings@a-klaw.com	rmccann@umich.edu
fjs@cpuc.ca.gov	rmiller@energy.state.ca.us
fortlieb@sandiego.gov	rmm@cpuc.ca.gov
freesa@thirdplanetwind.com	robert.boyd@ps.ge.com
garrett.hering@photon-international.com	ron.cerniglia@directenergy.com
garson_knapp@fpl.com	rprince@semprautilities.com
gary.allen@sce.com	rresch@seia.org
general.counsel@greenvolts.com	rroth@smud.org
george.wiltsee@sce.com	rsa@a-klaw.com
GloriaB@anzaelectric.org	rschmidt@bartlewells.com
gmorris@emf.net	rwalther@pacbell.net
GouletCA@email.laccd.edu	rwinthrop@pilotpowergroup.com
gpetlin@3degreesinc.com	saeed.farrokhpay@ferc.gov
gtd@cpuc.ca.gov	sara@solaralliance.org
gteigen@rcmdigesters.com	sas@a-klaw.com
GXL2@pge.com	sbeserra@sbcglobal.net
hal@rwitz.net	schurchi@energy.state.ca.us
hanigan@encous.com	sdhilton@stoel.com
hans@recurrentenergy.com	sean.beatty@mirant.com
harveyederpspc@hotmail.com	SEHC@pge.com
hcronin@water.ca.gov	sgallagher@stirlingenergy.com
hlouie@energy.state.ca.us	sha@cpuc.ca.gov
hraitt@energy.state.ca.us	shess@edisonmission.com
hrasool@semprautilities.com	sho@ogrady.us
hurlock@water.ca.gov	skg@cpuc.ca.gov
HYao@SempraUtilities.com	sls@a-klaw.com
info@calseia.org	smk@cpuc.ca.gov
jackmack@suesec.com	snuller@ethree.com
James.Stack@CityofPaloAlto.org	spauker@wsgr.com

janice@strategenconsulting.com	srovetti@sfwater.org
janreid@coastecon.com	ssmyers@att.net
jarmstrong@goodinmacbride.com	stephaniec@greenlining.org
jay2@pge.com	steveb@cwo.com
jbarnes@summitblue.com	steven.schleimer@barclayscapital.com
Jcox@fce.com	steven@iepa.com
jdalessi@navigantconsulting.com	susan.munves@smgov.net
jeanne.sole@sfgov.org	svn@cpuc.ca.gov
Jeff.Hirsch@DOE2.com	tam.hunt@gmail.com
jeffgray@dwt.com	Tashiana.Wangler@PacifiCorp.com
jenine.schenk@apses.com	tbo@cpuc.ca.gov
jennifer.chamberlin@directenergy.com	tburke@sfwater.org
jf2@cpuc.ca.gov	tcarlson@rrienergy.com
jfleshma@energy.state.ca.us	tcorr@sempra.com
jgorberg@lspower.com	tdarton@pilotpowergroup.com
jgreco@terra-genpower.com	tdillard@sppc.com
jim.howell@recurrentenergy.com	tfaust@redwoodrenewables.com
jim.metropulos@sierraclub.org	tim@marinemt.org
jjg@eslawfirm.com	tjaffe@energybusinessconsultants.com
jjw@cpuc.ca.gov	tobinjmr@sbcglobal.net
jkarp@winston.com	todd.edmister@bingham.com
jleslie@luce.com	Tom.Elgie@powerex.com
jluckhardt@downeybrand.com	tom_victorine@sjwater.com
jm3@cpuc.ca.gov	tomb@crossborderenergy.com
jmcfarland@treasurer.ca.gov	tpomales@arb.ca.gov
jmcmahon@crai.com	trf@cpuc.ca.gov
jmh@cpuc.ca.gov	trh@cpuc.ca.gov
jna@speakeasy.org	troberts@sempra.com
jnelson@psrec.coop	tsolomon@winston.com
jody_london_consulting@earthlink.net	ttutt@smud.org
Joe.Langenberg@gmail.com	tzentai@summitblue.com
johnrredding@earthlink.net	varaninie@gtlaw.com
jon.jacobs@paconsulting.com	vjw3@pge.com
Joni.Templeton@sce.com	vjw3@pge.com
jordan.white@pacificorp.com	vsuravarapu@cera.com
joyw@mid.org	vwood@smud.org
jpross@sungevity.com	wblattner@semprautilities.com
jrobertpayne@gmail.com	wbooth@booth-law.com
jsanders@caiso.com	wem@igc.org
jscancarelli@flk.com	wetstone@alamedapt.com
jsp5@pge.com	whgolove@chevron.com
jsqueri@gmssr.com	Will.Brieger@doj.ca.gov
judypau@dwt.com	william.v.walsh@sce.com
juliettea7@aol.com	wplaxico@heliosenergy.us
jweil@aglet.org	wwester@smud.org
jwoodwar@energy.state.ca.us	ygross@sempraglobal.com