UNITED STATES OF AMERICA

BEFORE THE

FEDERAL ENERGY REGULATORY COMMISSION

Request for Comments Regarding Rates,	)	
Accounting and Financial Reporting for	)	Docket Nos. RM11-24-000
New Electric Storage Technologies	)	and AD 10-13-000

COMMENTS OF THE NATIONAL HYDROPOWER ASSOCIATION ON THE JUNE 16, 2011 NOTICE OF INQUIRY RE THIRD-PARTY PROVISION OF ANCILLARY SERVICES; ACCOUNTING AND FINANCIAL REPORTING FOR NEW ELECTRIC STORAGE TECHNOLOGIES

I. Introduction

On June 16, 2011, the Federal Energy Regulatory Commission (the "Commission") issued a notice of inquiry on *Third-Party Provision of Ancillary Services; Accounting and Financial Reporting for New Electric Storage Technologies (RM11-24-000 and AD10-13-000)* (the "2011 NOI"). The 2011 NOI requested comments on two issues: (1) existing restrictions on third-party provision of ancillary services and actions the Commission could take to facilitate development of competitive markets; and (2) the adequacy of current accounting and reporting requirements related to energy storage devices.

The National Hydropower Association[1] ("NHA") appreciates this opportunity to offer input on these issues, each of which impacts the development and use of hydroelectric generation

[1] NHA is a non-profit national association dedicated exclusively to advancing the interests of the U.S. hydropower industry, including conventional, pumped storage and new hydrokinetic technologies. NHA's membership consists of more than 180 organizations including public utilities, investor-owned utilities, independent power producers, project developers, equipment manufacturers, environmental and engineering consultants and attorneys. In 2009, NHA established a Pumped Storage Development Council to promote the benefits of energy storage and to advocate for needed changes to facilitate increased pumped storage project development.

assets. With the appropriate market signals and regulatory structures in place, hydropower can meet its full potential to support electric reliability and the cost-effective integration of variable energy resources.

II. Comments

NHA believes that energy storage is vital to the successful, cost-effective integration of variable energy resources such as wind and solar generation.[2] As explained in these comments, existing policies such as the *Avista* restriction[3] and limits on sales of ancillary services to third parties prevent the robust development of new energy storage facilities, as well as the deployment of existing storage and conventional hydropower into ancillary services markets.

Section II.A of these comments discusses the *Avista* restriction and suggests an adaptation of *Avista* that would (1) enable an energy storage facility to participate in an ancillary services market without having to prove it lacked market power and (2) permit a transmission provider to acquire market-rate ancillary services to meet its mandatory service obligations.

Although these adaptations to *Avista* would make it easier for an energy storage facility (as well as conventional hydropower) to provide ancillary services, they would not solve the financing challenges faced by new energy storage, particularly grid-scale facilities like pumped storage hydropower. Section II.B therefore discusses the need to develop policies that would

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[2] For example, sufficient and cost-effective energy storage in the Pacific Northwest would have provided a generation sink in which to store excess nighttime wind generation, thus avoiding some of the contentious wind integration and "environmental redispatch" issues that the Bonneville Power Administration and numerous wind developers and stakeholders are now addressing in proceedings before the Commission and in the courts. *See Cannon Power Group, LLC, and Windy Flats Partners, LLC v. Bonneville Power Administration*, Ninth Circuit Case No. 11-72059 (2011); *Iberdrola Renewables, Inc., et al. v. Bonneville Power Administration*, FERC Docket No. EL11-44-000 (2011). In addition, the Midwest Independent System Operator ("MISO") is studying the utilization of about 5,500 MW of Manitoba Hydro in the MISO Energy and Ancillary Services Markets, including two new, large storage reservoirs with hydro power. The study will focus on integrating the operation of a hydro system with tremendous storage capability in Lake Winnipeg into a high wind area in the northern MISO footprint, where 9,000-23,000 MW of wind are projected to come on line. This approach underscores the partnership between energy storage and wind generation and is identical in concept to the integration of Denmark's wind generation and Norway's conventional hydropower system (which includes very large storage reservoirs).

[3] *Avista Corp.*, 87 FERC ¶ 61,223 ("*Avista*"), *order on reh'g*, 89 FERC ¶ 61,136 ("*Avista Rehearing Order*") (1999).

enable new energy storage facilities to compete to enter into long-term contracts with regional transmission organizations and transmission providers.

Finally, Section II.C addresses the Commission's questions concerning cost accounting and reporting for energy storage facilities by (1) explaining that existing cost accounting and reporting rules do not properly address several unique features of pumped storage hydropower facilities, and (2) recommending that the Commission take note of the similarities between electric energy storage and gas storage to develop a separate asset class that properly recognizes the unique features of electric energy storage.

A. The *Avista* Restriction.

Members of NHA own and operate, or are developing, both conventional and pumped storage hydropower projects. Due to its ability to increase or decrease generation on an as-needed basis, hydropower is well-suited to providing ancillary services such as operating reserves and regulation services. Balancing authorities rely on access to reserves (*i.e.*, generators standing by to produce more or less power) to balance generation and load requirements. There is a growing need for ancillary services to support grid functions due to changes in the portfolio of generation resources (specifically, the introduction of significant amounts of variable energy resources), but as the Commission notes, markets for ancillary services may not be developing in all regions of the country.[4]

In the 2011 NOI, the Commission indicated that it intended to re-examine the *Avista* restriction, which, among other things, requires market power studies to be performed when third

[4] 2011 NOI at ¶ 9. For instance, although hydropower in the Pacific Northwest has seen its flexibility reduced over time due to environmental restrictions, there are still many times of the year when flexible hydropower generation is available. However, to encourage this flexible resource to provide ancillary services to transmission providers trying to integrate variable resources, appropriate market signals must exist. Market incentives would be needed for non-federal hydropower capacity to be diverted from responding to heavy and light load demand.

parties provide ancillary services at market-based rates to transmission providers. Market power studies for ancillary services are difficult to perform in some areas, such as the bilateral markets of the West. NHA believes that the Commission can adapt *Avista* in a way that would facilitate the development of a more robust market for reserves and other ancillary services needed to integrate variable resources and support electric reliability. More liquid markets[5] would allow all potential providers of ancillary services, including new energy storage providers and conventional hydropower, to receive appropriate price signals. Such markets would also tend to reduce the rates that transmission customers must pay for the mandatory services.

The Commission correctly recognizes that competition is impaired, not enhanced, by requiring market power demonstrations that an electric storage developer or conventional hydropower facility may not be able to provide due to a lack of data. In actuality, although *Avista* is designed to shield transmission customers from a third party that wields market power in ancillary services, the doctrine effectively reduces the competitive options offered to the transmission operator. NHA thinks that *Avista*, if thoughtfully adapted to apply to independent developers of pumped storage hydro and other energy storage technologies as well as conventional hydropower, could enhance competition and foster efficient markets where no ancillary service providers, including transmission providers, have market power for such services.

[5] NHA recognizes that the PJM Interconnection and other eastern RTOs have already taken steps to establish competitive ancillary services markets. However, even these markets operate on a day-ahead and real time basis. As explained in Section II.B, such short-term ancillary markets will not by themselves facilitate the financing of energy storage projects, particularly grid-scale projects. Developers will still need a market willing and able to enter into long-term contracts for ancillary services and energy storage services.

In *Avista*, the Commission recognized that the applicant, a large retail utility with substantial electric generation resources, lacked the data to make a conventional demonstration of lack of market power for the provision of ancillary services. The Commission thus allowed

> Avista and other third-party suppliers who are unable to perform a reliable market power analysis to charge flexible rates for ancillary services if they establish the Internet-based site needed to guard against potential anticompetitive behavior and comply with . . . market monitoring reporting requirements . . . . [6]

The policy nevertheless prohibited sales of ancillary services by a third-party supplier at market-based rates in a few circumstances, including sales to a public utility that is purchasing ancillary services to satisfy its own obligations to customers under its open access transmission tariff ("OATT"). Thus, unless otherwise restricted under the *Avista* policy, a third party was granted authority to provide ancillary services at market-based rates where that third party had satisfied the Commission's market power thresholds with respect to energy sales, as well as satisfied other requirements to mitigate potential anticompetitive behavior.

> Our action here authorizing Avista to sell ancillary services at market-based rates is premised, in part, on [the Commission's] prior authorization [to Avista] to sell power and energy at market-based rates. Similarly, we will authorize other potential third-party providers of ancillary services to provide such services at flexible rates only if they first are otherwise authorized to sell power and energy at market-based rates.[7]

For market entrants who own both conventional generation facilities and energy storage, or who own only conventional hydropower generation, the *Avista* restriction would be satisfied if the owner of the generation facilities had "prior authorization to sell power and energy at market-

[6] *Avista*¸87 FERC ¶ 61,223 at 8.
[7] *Id.* at n.1.

based rates" and was willing to establish an Internet-based site to guard against potential anticompetitive behavior and to comply with market monitoring reporting requirements.

It follows from this principle that owners of standalone energy storage facilities—*i.e.*, owners of resources that cannot generate power without first absorbing power from energy generation facilities—necessarily satisfy the *Avista* standard without requiring any market power analysis where ancillary services can be sold at market-based rates. NHA therefore suggests that energy storage providers that are bidding into competitive markets should be considered as lacking market power *per se*.[8]

Avista unintentionally created a much larger impediment to fostering competitive markets in ancillary services: the restriction on the parties to whom an energy storage owner[9], conventional hydropower owner or any other provider may sell ancillary services at market rates. Particularly in areas not served by regional transmission organizations – like most of the Western Electricity Coordinating Council region – *Avista* prevents market-based pricing of ancillary services to transmission providers serving customers under their OATTs. This prohibition suppresses the deployment of existing conventional hydropower capacity for the provision of ancillary services and the development of new competing sources of ancillary services, such as pumped storage or other energy storage facilities, that could help transmission providers who are stretched thin in their ability to integrate the growing fleet of variable energy resources.

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[8] At first blush, the caveat "only if they first are otherwise authorized to sell power and energy at market-based rates" might seem to restrain the Commission's approval of market-based rates for the provision of ancillary services by an owner of an energy storage project who does not own any energy generation (as opposed to energy storage) facilities. However, in *Avista* a lack of generation market power constituted a sufficient showing even for a utility *with* energy generation facilities. Therefore, the Commission should be able to find easily that a provider of only storage services similarly lacks market power.

[9] An energy storage provider may be the owner of a newly developed energy storage facility (including a pumped storage facility) but may also include the owner of a conventional hydropower facility that can provide storage services.

In the *Avista Rehearing Order*, the Commission noted that third parties could sell ancillary services to transmission providers at market rates, but emphasized that they could only do so when the purchasing transmission provider would in turn sell those ancillary services off its system.[10] The Commission reasoned that it was able to grant flexible pricing in those circumstances "only because the price charged by the third-party supplier is disciplined by the obligation of the transmission provider to offer these services under <u>cost-based</u> rates."[11] NHA suggests that third-party ancillary services sales to transmission providers meeting their mandatory service obligations are similarly disciplined such that the *Avista* prohibition is not necessary. An inherent price cap exists, and the Commission's experience in establishing secondary transmission markets provides the appropriate guidance.

As long as transmission providers are required to continue providing ancillary services at cost-based rates, and in doing so are required to consider in good faith their own costs of self-supply, transmission customers will pay ancillary services rates equal to the lesser of the market rate or a transmission provider's cost of self-supply. In other words, market rates will be sufficiently disciplined by a price cap equal to the cost of self-supply. Where the economics favor market rates, transmission customers will benefit by avoiding the higher costs of a transmission provider's self-supply from existing or expanded resources. Of course in some circumstances, self-supply would win out over market rates, and transmission customers would again be the beneficiaries. In either scenario, transmission customers could use Federal Power Act section 205 and 206 proceedings to challenge rates that may not meet the lesser-of standard. Under *Avista*, this lesser-of scenario conceivably exists today—*i.e.*, customers would seem to pay the lesser of the transmission provider's cost of self-supply and a third-party's cost-based

[10] *Avista Rehearing Order*, 89 FERC ¶61,136 at 5-6.
[11] *Id.* at 6 n.17 (emphasis in original).

rates. The problem is that no competitive market for cost-based ancillary services exists in many regions, which tends to leave transmission customers paying the inherent price cap (the cost of self-supply). Accordingly, NHA believes that the Commission should further encourage the development of competitive markets by removing the *Avista* prohibition against a transmission provider acquiring market-rate ancillary services to meet its mandatory service obligations.

B. The Commission Should Develop Policies That Allow RTOs to Enter Long-Term Fixed-Price Contracts with Energy Storage Owners.

The adaptation of the *Avista* doctrine as proposed in Section II.A would enhance the ability of an energy storage owner to participate in the ancillary services markets without having to make a burdensome (if not impossible) showing that it lacks market power in those markets. But this approach on its own will not enable the financing of most energy storage projects, particularly new grid-scale pumped storage projects. To accomplish that, the Commission should develop policies that allow regional transmission organizations and independent system operators (collectively, "RTOs"), as well as stand-alone transmission providers, to enter into long-term fixed-price contracts with energy storage owners, including owners of pumped storage facilities. These fixed-price contracts would provide the purchaser not only with specified ancillary services for the term of the contract, but also with energy storage services that are uniquely suited to manage the growing penetration of variable energy generation.

NHA believes that grid-scale storage would facilitate the development, integration, expansion and economics of variable generation. Pumped storage in particular is a proven and existing technology, with over 23,000 megawatts of capacity currently installed and operating in the United States. Unlike the pumped storage facilities that were built in the 1970s and 1980s, however, new energy storage facilities will be built in competitive markets in which the old rate-based regulated utility generation model no longer applies—much of the nation's energy infrastructure is now owned or being developed by independent power producers who lack utility-rate base cost recovery structures.

Moreover, modern energy storage will mainly be used to manage generation from variable resources like wind and solar rather than to store energy generated by thermal units. Energy storage facilities, especially at grid-scale, are uniquely able to offer not only ancillary services, as discussed in Section II.A, but also energy storage services—for example, taking delivery of excess intermittent energy during off peak hours and storing it until it can be released at a later time to meet peak loads. Like other capital-intensive development, grid-scale energy storage is very hard to develop in the current regulatory environment because the developer cannot identify and secure the long-term revenue stream required to finance a capital-intensive project, except in cases where the project can be included in a utility's rate base. To be developed to support renewable energy, energy storage facilities require a market that is permitted to enter into long-term contracts for the services that energy storage offers. Unfortunately, precedent in two Commission decisions poses the barrier to such a market.

In two important decisions, *Nevada Hydro Co*., 122 FERC ¶ 61,272 (2008) ("*Nevada Hydro*"), and *Western Grid Development, LLC*, 130 FERC ¶ 61,056 (2010) ("*Western Grid*"), the Commission struggled with a conundrum regarding employment of pumped storage facilities by RTOs. In each of these decisions, the Commission weighed the competing policies of encouraging RTO use of new and more efficient technologies, on the one hand, and of maintaining the separation of transmission and generation markets, on the other hand.[12] The 2011 NOI and the ongoing proceedings in Docket No. AD10-13-000 provide the Commission with the opportunity to reexamine and improve on its prior determinations.

[12] Similar issues can arise if non-RTO transmission operator seeks to enter a long-term energy storage control agreement.

As the Commission discussed in *Nevada Hydro*, pumped storage facilities can supply services otherwise provided by transmission facilities and also can provide ancillary services otherwise provided by generation facilities. The main market for the products a pumped storage facility can produce may well be RTOs and other transmission providers. RTOs in particular generally provide both transmission and transmission ancillary services for integration of intermittent generation resources. Moreover, in such markets, the RTO probably is the entity best able to provide the transmission ancillary services because it can control and take bids from a more comprehensive array of transmission and generation resources than can either variable generators themselves or retail utilities.

For the delivery of some kinds of transmission ancillary services, grid-scale energy storage facilities may be the preferable option, in both monetary cost and environmental impact. Storage facilities may allow new transmission facilities to be avoided and may lead to a substantial reduction in consumption of fossil fuels, particularly during nighttime light load hours when the cycling of simple-cycle gas turbines may be required to provide rapid ramping and also during peak hours in which the least efficient generation resources otherwise must be employed.[13] Perhaps most important, given renewable portfolio standards and regional and state carbon reduction goals, pumped storage facilities can permit integration of greater amounts of variable resources at lower cost and with less use of thermal peaking generation-following resources in part because of their ability to absorb and store energy when it is not needed by the grid.[14]

[13] See discussion in Section II.A above regarding evaluating least-cost resources.
[14] Energy storage has an important advantage over thermal peaking resources: at night, when terrestrial wind generation tends to peak, energy storage can be used as a generation sink. A thermal generator does not perform this important function, nor does transmission, which is another reason why energy storage should be treated as a separate asset class as discussed in Section II.C below.

However, pumped storage and other grid-scale energy storage facilities are typically quite large and, despite enjoying a low unit cost per kW of installed capacity and low long-term operating costs, have high total initial capital costs. As a result, obtaining financing is difficult if not impossible for facilities that bid into day-ahead or hour-ahead markets, because such markets do not ensure the storage facility a creditworthy revenue stream sufficient to satisfy potential lenders.

In addition to the difficulty of financing high total capital cost resources without an assured revenue stream, the pumped storage developer faces a "Catch-22" situation that the RTOs and the Commission already have recognized with respect to development of new transmission lines, and to a lesser extent with respect to new fossil-fueled generation capacity resources. Essentially, the construction of economic levels of facilities to relieve either transmission congestion or generation capacity shortages will reduce or eliminate the amount of any congestion or capacity shortage payments that the facility owner might rely on to repay the capital costs of the facilities. RTOs and other transmission providers capture such cost reduction benefits by entering long-term contracts that enable the installation of needed transmission facilities. NHA believes that this model could work for grid-scale energy storage facilities.

Similarly, long-term agreements are needed to facilitate the financing of grid-scale energy storage facilities, including pumped storage, that can provide valuable benefits to and improve the operation of RTO and other transmission provider systems by providing both ancillary services and energy storage services. As the Commission recognized in *Western Grid*, even if the Commission erects no contracting barriers, transmission providers will contract with energy storage providers only if the transmission providers find such agreements to be superior to other alternatives:

> Pursuant to CAISO Tariff section 24.1.1, the CAISO will not approve the Projects if a superior alternative project is proposed or if the Projects do not pass a cost-benefit analysis. Thus, if the CAISO approves the Projects, they would be paid for by ratepayers because the CAISO had found that they were the most efficient solution proposed.[15]

NHA thus urges the Commission to consider reasonable operating rules, consistent with competitive markets, that would allow, although not mandate, RTOs and other transmission providers to make long-term arrangements to acquire use of energy storage capabilities when the RTOs or other transmission providers find such arrangements to be their most efficient solution. Such energy storage capabilities could be used to shift renewable energy generation to load, to displace requirements for transmission facilities and to provide valuable transmission ancillary service benefits.

NHA recognizes that RTOs and other transmission providers should maintain functional separation and transparency in the markets for electric generation and that all suppliers of ancillary services and energy storage services should compete fairly. However, pumped storage facilities only store and shape electric energy delivered by generation resources and are not capable of producing additional net energy supplies. With appropriate operating transparency in place, a transmission provider's use of storage facilities for provision of ancillary services and energy storage services can be made fully consistent with an open and robust generation supply market. For example, the RTO or other transmission provider could direct operation of the pumped storage units or other energy storage technologies in accordance with published protocols, available to all market participants. The RTO or other transmission provider also could have published standing policies with regard to operating available pumped storage

[15] *Western Grid*, 130 FERC ¶ 61,056 at 47.

capacity to follow within-hour changes in variable resource generation. Such operations could provide substantial value, without adversely impacting the benefits from RTO markets. As long as such storage facilities are competing fairly with other providers in a competitive market for ancillary services and energy storage services, efficiency of operation is enhanced.

C. Creating a New Asset Class for Energy Storage and Accounting for the Costs of Electric Storage Technologies.

1. NHA's Comments Concerning Pumped Storage Hydropower Assets.

In the 2011 NOI, the Commission stated that accounting and financial reporting for pumped storage assets and operations are already in place, suggesting that the Commission does not plan to include pumped storage hydropower in its decisions about how energy storage technologies are to be treated in a new ancillary services rate accounting mechanism.[16] NHA respectfully disagrees with the Commission's approach and believes that pumped storage is at best a "forced fit" into existing accounting and reporting requirements.

NHA recognizes the Commission's perspective that asset accounting for pumped storage was established together with the development of the existing pumped storage fleet. And NHA agrees that certain portions of FERC Form 1 generally do a satisfactory job of determining the units of property as they relate to typical hydropower installations. However, FERC Form 1 should be revised to better represent pumped storage assets, which are fundamentally different from plants that are designed to produce net electric energy output. Suggested improvements and NHA's reasons for requesting them are as follows:

- FERC Form 1, Pumped Storage Generating Plant Statistics, Line 6: "Plant hours Connect to Load while Generating." The total hours an energy storage facility is

[16] *See, e.g.*, 2011 NOI at n.46 (the Commission "does not seek comment of whether the current accounting and reporting requirements for pumped storage hydroelectric assets or operations should be revised").

synchronized and connected to the grid is important to identify. A pumped storage station's effectiveness is based on its total "utilization factor," which is the sum of hours generating, pumping and condensing. NHA recommends the Commission change line 6 to read "Plant hours Connect to Load." This would include all hours synchronized to the grid. If further detail is required, then the Commission should consider adding two line items to capture the "Plant hours Connect to Load while Pumping (charging)" and "Plant hours Connect to Load while Condensing."

- FERC Form 1, Line 38: "Expenses for KWh (line 37/9)." This is an incorrect calculation to determine the true cost and representation of the operations and maintenance ("O&M") expenses of pumped storage facilities. NHA recommends that the calculation be changed to include the pumping (or charging) hours to the calculation as follows: "Line 37/ (9+10)." NHA concurs with the Commission that the asset class cost accounting for pumped storage facilities in lines 13 through 35 of FERC Form 1 is satisfactory to capture accurately the capital and O&M costs for pumped storage facilities. However, these costs also include the incremental capital and O&M costs of the equipment required to allow reversible pump turbine operations, further supporting the logic above in including all pumping energy plus generation energy in the $/KWh calculation.

At several points, the 2011 NOI recognizes the need for accounting and reporting changes that would also affect pumped storage facilities. For example, the Commission noted that

> some public utilities will need to purchase or internally generate power for use in storage operations. However, the USofA does not have specific accounts for recording the cost of power purchased or generating expenses incurred in storage operations. Therefore,

> we seek comments on the appropriate accounting for these items.[17]

The Commission also sought comments concerning whether new accounts for energy storage plants and equipment should be created and an existing account be revised, whether new accounts should be created and no existing accounts used, or whether the existing primary plant accounts sufficiently provide for energy storage plants and equipment.[18] The Commission's requests for comments on these points underscore NHA's view that FERC Form 1 needs to be adjusted to address pumped storage assets, because the questions posed are not adequately addressed by FERC Form 1 and would be relevant to a pumped storage facility just as they would be to any other energy storage facility.

In its discussion of the use of existing pumped storage resources to arbitrage the difference between the sales price of on-peak and off-peak electricity, the Commission noted that purchases of power for resale are to be recorded at cost in Account 555, Purchase Power, and concluded that "this account may sufficiently provide for the recording of the cost of electricity stored in storage operations that is sold in wholesale electricity markets."[19] NHA notes that line 36 on FERC Form 1 accounts for "Pumping Expenses," and the pumped storage industry understands that the cost of pumping energy is to be included on this line. If the Commission changes the accounting for pumping (or charging) energy that is sold in wholesale electricity markets for energy storage facilities, the Commission should apply the same standard to pumped storage facilities.

The Commission also inquired whether power purchased to attain a state of initial charge should be accounted for as a base charge and included as a component cost of energy storage

[17] *Id.* at 28 ¶ 31.
[18] *Id.* at 31 ¶ 37.
[19] *Id.* at 32 ¶ 38.

plant and equipment, asking whether there are any alternative methods to account for power purchased to initially attain a state of charge.[20] NHA concurs with the Commission's suggestion that there needs to be a new accounting mechanism to account for the energy required for initial unit testing and commissioning. In particular, for closed-loop pumped storage projects (off of any main stem river channel), where the initial filling of the water conveyance tunnels and the reservoirs is not from normal stream flow, the first unit testing entails pumping or charging the upper reservoir in stages. At this point in the development of a project, the station is months away from being declared "commercial," and this required unit testing demands energy from the grid in order to achieve a full upper reservoir (*i.e.*, considered a fully charged state for a pumped storage facility). Additional unit testing is also required after the state of initial charge, and the energy produced during generation testing can be deducted from the pumping energy utilized to accurately, and transparently, account for the total energy required to achieve initial state of charge and reach commercial operation. NHA believes it is entirely appropriate to account for the supply of pumping (or charging) energy during the station testing phase in the base capital cost of the project.[21]

The Commission also asked whether existing O&M expense accounts are sufficient to capture costs associated with storage operations and whether any revisions are required.[22] NHA believes that the existing FERC Form 1, if modified as recommended in NHA's comments, is sufficient to account for costs for storage operations. NHA does not recommend separating O&M costs based upon the service being provided to the transmission system operator.

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[20] *Id.* at 36 ¶ 44.
[21] In addition, the "initial fill" of water at a pumped storage facility is analogous to "cushion gas" or "base gas" in a gas storage facility and should be included in the capital costs of a pumped storage project.
[22] 2011 NOI at 40 ¶ 49.

2. Recognizing a New Asset Class for Electric Energy Storage.

In its original Notice of Inquiry concerning electrical energy storage (the "Original NOI"),[23] the Commission described storage practices in the gas industry as follows:

> Most interstate natural gas storage facilities are operated as transmission facilities and offer open access storage services to customers who contract for that service; the storage facility operator may not buy and sell the gas commodity at that location. Contract storage service is offered at either cost-based or negotiated rates for the service of storing customers' gas and only those storage customers buy and sell the gas commodity itself (storage customers hold "title" to the gas held in storage). Generally, the customer pays a reservation fee and a storage fee based on usage with penalties for over and under scheduling, though this may not always be the case with negotiated rates. Either way, the time arbitrage gains on the stored gas are the profit or loss for the customer, not the gas storage operator.[24]

The Commission noted that this gas storage model "has not yet been adopted for electric storage facilities but may provide an attractive alternative business model for some storage operators."[25] NHA agrees with the Commission that electric energy storage is indeed analogous to gas storage and that the gas storage model is useful for recognizing a new asset class of electric energy storage.

Storing and releasing electricity to meet daily peak electricity demand is analogous to storing gas so that it can be withdrawn and used to meet weekly, monthly or seasonal load variations. In the gas storage industry, a certain amount of capacity can be used or withheld to inject into the gas system to respond to system pressure variations, to maintain contractual balance in order to avoid imbalance penalties and to address unforeseen changes on the system,

[23] *Request for Comments Regarding Rates, Accounting and Financial Reporting for New Electric Storage Technologies*, Docket No. AD10-13-000 (June 11, 2010).
[24] *Id.* at 9. NHA notes that customers of a gas storage facility may also pay injection and withdrawal fees, which may be in addition to the reservation and storage fees described in the Original NOI.
[25] *Id*.

such as a malfunction or casualty to production or distribution systems. This is analogous to the ancillary services that electric energy storage facilities are well equipped to provide to the electric power industry. At an electric energy storage facility, a portion of the electric energy storage capacity could be sold under a long-term contract to provide a revenue stream for financing, while a portion could be reserved to be sold to RTOs and transmission providers in an established market for ancillary services. A gas storage facility can offer "no notice" service where gas held in storage can be released immediately upon request in an emergency. Similarly, an RTO or transmission provider could call upon an electric energy storage facility to discharge all or some part of its reserve capacity at a moment's notice. Like a gas storage facility, the cost of an energy storage facility could largely be recovered through long-term storage contracts that would be market-based and offered through an open season bidding process. Demand charges could be used to recognize the volume of energy stored in the facility and the rate of discharge (often referred to as a "bifurcated demand charge" in the gas storage industry). Such facilities could also charge a use or access charge (analogous to the "use charge" in gas storage). In most cases, the title to the stored electricity in an electric storage facility, like title to the gas in a gas storage facility, would remain with the party "injecting" and "withdrawing" the energy—the owner of the storage facility would not take title to the energy.[26] Similarly, the electric energy storage facility could "toll" electric energy for a third party—for example, a utility purchasing or self-generating nighttime wind energy in excess of its load could deliver the excess energy to the storage facility and then withdraw it the next day to meet the utility's peak loads.

Like gas storage, electric energy storage should be categorized as a unique asset class—it is not generation; it is not load; and it is not transmission. It can provide a full range of ancillary

[26] To the extent that an electric energy storage facility stored the facility owner's energy, *e.g.*, where a wind developer owned both a wind generator and a battery used to store and manage the generator's output, the owner would obtain a market-based rate with respect to the generator/battery combination.

services but it can also provide unique new storage services such as the ability to shift off peak intermittent generation to load. Energy storage is thus a new asset class altogether. By recognizing a new asset class for electric energy storage facilities, the Commission would facilitate appropriate cost accounting and financial reporting for those facilities.

In its Original NOI, the Commission suggested that

> [t]he primary potential barrier to [the gas storage] type of business model appears to be financial. An independent contract storage provider might need to sign up long-term customers in advance under bilateral contracts, perhaps following an open season, in order to secure financing for construction of the facility. Storage facilities with large upfront capital costs, like pumped storage, may have difficulty attracting sufficient customer interest during the crucial pre-construction financing phase. However, storage service from newer storage technologies with lower up-front capital costs may be easier to finance and market in this way.[27]

NHA respectfully submits that the primary potential barrier to the gas storage model is not financial but regulatory. The Commission's current application of the *Avista* restriction effectively eliminates RTOs and transmission providers as potential markets for electric energy storage services. If the *Avista* doctrine were adapted as suggested in these comments, NHA believes that the gas storage model would work very effectively to create an environment in which small and large energy storage facilities could be effectively developed, financed and deployed.

III. Conclusion

The Commission should adapt the *Avista* restriction to enable an energy storage facility—or a conventional hydropower facility-- to participate in an ancillary services market without having to make a burdensome if not impossible showing that it lacks market power. In addition,

[27] Original NOI at 9-10.

energy storage providers as well as hydropower facilities should be allowed to sell ancillary services to transmission providers for use in meeting their mandatory service obligations. Equally important, the Commission should adopt policies that enable energy storage facilities to enter into long-term contracts for ancillary services and energy storage services with RTOs and transmission providers.

In future proceedings concerning electric energy storage, the Commission should recognize that storage facilities – including hydroelectric pumped storage projects – constitute a separate class of assets that, if encouraged, will enhance competition in the power markets. Storage assets produce no net electric generation but serve to shape the output of variable electric generation facilities to better meet load requirements. As a result, energy storage facilities are vital to the successful and cost-effective integration of variable energy resources and to the achievement of renewable portfolio standards throughout the United States. Moreover, although storage assets are not transmission assets, they can relieve transmission constraints and can shape variable energy generation so as to reduce the amount of new transmission required to bring remote variable energy resources to market. And of course, storage assets can supply traditional ancillary services.

A robust development of this class of assets, if encouraged through market pricing allowance, can only increase the competition available, improve service and lower costs, as compared to the current system in which employment of this class of assets is largely unavailable due to regulatory rather than financial constraints.

NHA greatly appreciates the opportunity to comment on these important topics and looks forward to working with the Commission on the next steps, presumably including a notice of proposed rulemaking, to develop the regulatory framework to answer the questions posed in both the Original NOI and the 2011 NOI.

Respectfully submitted,

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