The James River at Jamestown
VIRGINIA

THE JAMES IS THE FOUNDING river of the nation, with the first successful English colony in the New World established along its banks. It’s a place where civilizations came together. Now, 400 years later, visitors from around the world come to experience history where it happened.
THE JAMES and its pristine landscape connect some of our nation’s most important historic sites, including Jamestown Island, Colonial Parkway, and Carter’s Grove. Visitors today experience a riverscape that is largely unchanged from the 17th century.

HISTORY

Named to the National Trust’s 2013 11 Most Endangered Historic Places list, the James River has been the site of significant events stretching back before the founding of the United States. As the location of the first successful English colony in America at Jamestown in 1607, a transportation route during the Revolutionary War, the site of Civil War battles, and the keystone segment of the nation’s first nationally designated water trail, the James is integral to the story of America, as well as the region’s environmental and economic well-being.

THREAT

Dominion Virginia Power has proposed building a transmission line across the James River at Jamestown that includes 17 towers, some up to 295 feet tall. This project would dramatically alter the landscape and put at risk decades of investment by the public and private sectors to protect this important part of our country’s past.

OPPORTUNITY

The National Trust is advocating to save the James River through state and federal regulatory review processes. It also mounted a strategic public outreach campaign to urge Dominion to find an alternative route.

FAST FACT

The United Kingdom’s Queen Elizabeth II has visited Jamestown twice, most recently on Jamestown’s 400th anniversary in 2007.
THE JAMES RIVER TRANSMISSION LINE – SUMMARY OF PROPOSED ALTERNATIVES

I. Executive Summary

Background: The National Trust for Historic Preservation has been advocating against construction of a 500 kV overhead transmission line proposed by Dominion Virginia Power. The line, as currently proposed, would cross the James River in the viewshed of Jamestown Island, Colonial Parkway, Carter’s Grove plantation and the Captain John Smith Chesapeake National Historic Trail. The National Trust has been actively working to encourage Dominion to pursue an alternative project since 2013 when the James River was named to our list of 11 Most Endangered Historic Places.

The need for Dominion’s proposed project is being driven by the impending shutdown of two of the three generating units at the Yorktown Power Station. Two coal-fired units (Yorktown 1 and 2) are required to close due to a federal law called MATS (Mercury Air Toxics Standard). Absent federal regulatory intervention, the last date that Yorktown 1 and 2 can operate without violating MATS is in April 2017.

Yorktown 3 is an oil-burning generating unit that it is not required to close by MATS. However, it is limited to running 8% of the time due to MATS. Once Yorktown 1 and 2 close, a plan should be in place to ensure that the energy system in the North Hampton Roads Area (NHRA) of Virginia complies with National Energy Regulatory Commission (NERC) reliability standards during times of peak demand (i.e., during the summer when electrical needs are the highest). Dominion’s preferred overhead alternative addresses the NERC compliance issue and meets the power needs of the region, but would create significant harm to nationally significant historic resources along the James River.

Dominion has consistently represented its preferred 500kV overhead alternative as the only realistic solution. A recent Op-Ed in the Richmond Times Dispatch authored by a Dominion representative stated that:

“There is no better solution. Dominion considered dozens of alternatives. They all came up short. They could not deliver enough electricity to meet the needs of the Peninsula, were of unproven reliability, were even more costly for customers than putting emissions controls on the Yorktown coal units, could not be completed on time, or would be more disruptive to the environment.”

In contrast, the National Trust has consistently stated our position that, if this problem is approached with a problem-solving mindset, other alternatives could be identified that would satisfy all relevant electrical criteria and save the
irreplaceable historic resources along the James River. To that end, the National Trust retained the firm of Tabors Caramanis Rudkevich (TCR) to identify one or more alternatives that would not require an overhead crossing of the James River and would meet all relevant planning and reliability criteria.

**Review Process:** TCR performed engineering (power flow) analyses and developed four alternatives that would meet the energy reliability needs, cost less, can be constructed in less time, and do not require constructing an overhead transmission line across the river.

Dominion’s proposed James River project has two parts: the 500 kV river crossing and a new 230 kV line that runs south from James City County. The alternatives that TCR developed assume that the 230 kV portion of the project is built, and seek to replace only the 500 kV river crossing portion of the project.

To identify the four alternatives, TCR used information that Dominion has filed with the Federal Energy Regulatory Commission or has provided through the federal permit review process being led by the Army Corps of Engineers. TCR also used power flow modeling software that is standard in the industry. The four alternatives identified by TCR are not an exhaustive list of potential alternatives.

**Results Summary:** The four alternatives require a mix of reconductoring (upgrading wires on existing towers), reconfiguring (operating the electrical system differently), and operating Yorktown 3 (oil-fired plant not required to close by MATS) to meet summer peak demand and/or as a voltage regulator. The fourth alternative is a construction option that would involve building new 230 kV lines in existing Right of Ways (ROW) or along highways.

<table>
<thead>
<tr>
<th>Alternative</th>
<th>Estimated Cost</th>
<th>Estimated Time to Construct</th>
</tr>
</thead>
<tbody>
<tr>
<td>A – Reconductor &amp; Reconfigure</td>
<td>$78 million</td>
<td>&lt; 12 months</td>
</tr>
<tr>
<td>B – Yorktown 3 online during Summer Peak</td>
<td>Increased generation costs only*</td>
<td>Available today</td>
</tr>
<tr>
<td>C – Yorktown 3 Standby</td>
<td>$12 million</td>
<td>&lt; 12 months</td>
</tr>
<tr>
<td>D – Critical ROW Bypass</td>
<td>$72 - $132 million</td>
<td>&lt; 20 months</td>
</tr>
<tr>
<td>Dominion’s Preferred Overhead James River Crossing</td>
<td>$100 million + $85 million (mitigation funding)</td>
<td>20 months</td>
</tr>
</tbody>
</table>

* Under July – September 2016 conditions, these costs are estimated to be $12 million/year.

**Conclusion:** There are at least four alternative projects that could be pursued that avoid the need to construct an overhead 500KV transmission line across the James River. Each of these alternatives costs less to construct, can be built more quickly, meets all relevant reliability standards and energy needs in the region and protects the historic landscape and resources along the James River.
II. Summary of Alternatives

To satisfy NERC criteria, a project must be able to protect grid reliability under various planning scenarios. The main drivers for the James River project are: extreme events that could result in the outage of all lines in a right of way (Extreme Right of Way Contingencies), an outage of both of the existing 230 kV lines that cross the James River near Newport News (Tower Contingency), or a series of sequential outages of 230 kV lines in the region (Single Element Contingency). The following is a brief summary of the four alternatives, which satisfy these criteria. More details about the alternatives are available in the Appendix.

Alternative A – Reconductor and Reconfigure

• Reconductor 230 kV line Lightfoot – Kings Mill (section of line 209, ~9 miles)
• Reconductor 115 kV line Lanexa – Toano (section of line 58, ~6.5 miles)
• Enable the generator at Yorktown 3 to run continuously as a synchronous condenser (voltage support)
• Reconfigure the system under Summer Peak conditions:
  • Energize existing 115 kV line Toano – Kings Mill (section of line 58)
  • After an outage of line 209 or 285, energize 115 kV line Lanexa – Dow Tap (West end of line 34), de-energize 115 kV line Yorktown – Grafton (East end of line 34), and split the Skiffes Creek 115 kV so that line 34 is not connected to other facilities at Skiffes Creek
• Reconductor 230 kV line Chuckatuck – Newport News and Newport News – Shellbank (~18 miles in total)
• Reconductor 230 kV line Poolesville – Winchester (~29 miles)*

* NOTE: Alternatively, a Special Protection Scheme (SPS) could be developed that would allow shedding of 225 MW of load upon overload of 230 kV Benns Church – Copeland, and keep Yorktown 3 on stand-by (would only occur if one of two Extreme Right of Way contingencies occur, and would last only until Yorktown 3 is started, up to 8-10 hours); see Alternative C. A SPS can be developed that identifies power users who volunteer to have load dropped in exchange for payments.

Alternative B – Yorktown 3 On Summer Peak

• Start and dispatch Yorktown 3 at 310 MW** (minimum load, per DVP letter to NPCA 9/12/16) under summer peak conditions
• Under all other seasonal conditions analyzed (winter peak and spring minimum load), TCR identified no violations to NERC Standards or DVP Planning Criteria in the absence of the overhead 500KV line

• Overhead lines in the NHRA area are predominantly thermally limited; with lower ambient temperatures, transmission capacity increases significantly

• Under the conservative assumption that summer peak conditions occur 5 days/week for 12 weeks per year, the annual capacity factor of Yorktown 3 would be 6.4% (well below the 8% limit under MATS)

  ** NOTE: As implied or explicitly stated in different filings, DVP has indicated that Yorktown 3 will be available at least through 2026.

**Alternative C – Yorktown 3 Stand-by**

• Start and dispatch Yorktown 3 at 310 MW (minimum load) under summer peak conditions upon the occurrence of a critical Single-Element Contingency

• Enable the generator at Yorktown 3 to run continuously as a synchronous condenser

• Reconfigure the system under Summer Peak conditions (pre-contingency):
  
  • Energize existing 115 kV line Toano – Kings Mill (section of line 58)
  • Energize 115 kV line Lanexa – Dow Tap (line 34), and split the Skiffes Creek 115 kV so that line 34 is not connected to other facilities at Skiffes Creek

• Develop a SPS to drop 225 MW of load at selected NHRA feeders upon overload of 230 kV Benns Church – Copeland (would only occur if one of two Extreme Right of Way contingencies occur; would last only until Yorktown 3 is started, estimated to be 8-10 hours)***

  *** NOTE: An SPS can involve seeking fast-response contingency reserves through key large users or through other demand management alternatives. Alternatively, if 230 KV lines Chuckatuck-Shellbank and Poolesville-Winchester are reconductored, no SPS is necessary; see Alternative A.

**Alternative D – New 230kV Paths**

• Tap existing 230 kV line (#2075) near Brookwoods

• Tap existing 230 kV line (#224) near Slaterville

• Build new 230 kV line between Brookwoods and Slaterville (~18 miles, along I-64 or route 249)
• Build new 230 kV line between Hayes and Harmony (~25 miles, *on existing right of way*)
• Reconduct or rebuild 230 kV line Lanexa – Slaterville (~5.75 miles)
• Enable the generator at Yorktown 3 to run continuously as a synchronous condenser
• Reconfigure the system under Summer Peak conditions:
  • Energize existing 115 kV line Toano – Kings Mill (section of line 58)
  • Energize 115 kV line Lanexa – Dow Tap (West end of line 34) and split the Skiffes Creek 115 kV so that line 34 is not connected to other facilities at Skiffes Creek
  • After the outage of line 285, de-energize line Chickahominy – Lanexa circuit 2
Alternatives to Surry – Skiffes Creek 500 kV Overhead Project

Identification and Power Flow Analysis

Richard D. Tabors, Ph.D.

USACE, Norfolk, VA
October 28, 2016
Agenda

• Scope of Work
• Project Summary
• Background
  • Surry – Skiffes Creek Project
  • NERC Standards and Dominion Transmission Planning Criteria
  • Available Data and Analysis Methodology
  • Main Drivers for Transmission Solutions in NHRA
• Alternatives to Surry – Skiffes Creek 500 kV
Scope of Work

• Tabors Caramanis Rudkevich (TCR) was retained by the National Trust for Historic Preservation (NTHP) to identify alternatives to the Surry – Skiffes Creek 500 kV overhead transmission project, and to evaluate them using power flow simulations. The alternatives must meet NERC Reliability Standards, be implementable and should be as cost-effective as possible.
Project Summary

- TCR based its analyses on Dominion Virginia Power (DVP) reported reliability criteria and FERC filed transmission data (FERC Form No. 715)

- TCR identified and fully evaluated four complementary, specific alternatives to the Surry-Skiffes proposed river crossing *each of which meets all reliability requirements, is generally less costly and can be implemented in a shorter period of time*

<table>
<thead>
<tr>
<th>Alternatives</th>
<th>Estimated Cost</th>
<th>Estimated time frame</th>
</tr>
</thead>
<tbody>
<tr>
<td>A – Reconductor &amp; Reconfigure</td>
<td>$78 million</td>
<td>&lt; 12 months</td>
</tr>
<tr>
<td>B – Yorktown 3 online during Summer Peak</td>
<td>increased generation costs only*</td>
<td>Available today</td>
</tr>
<tr>
<td>C – Yorktown 3 Standby</td>
<td>$12 million</td>
<td>&lt; 12 months</td>
</tr>
<tr>
<td>D – Critical ROW Bypass</td>
<td>$72 - $132 million</td>
<td>&lt; 20 months</td>
</tr>
<tr>
<td>Overhead James River crossing</td>
<td>$100 million + $85 million (mitigation)</td>
<td>20 months</td>
</tr>
</tbody>
</table>

* Based on the revenue shortfall (fuel and other operation cost minus PJM energy market revenue) of operating Yorktown 3 for 12 weeks, 5 days/week, under July – September 2016 conditions, these are estimated at $12 million/year.
The Surry – Skiffes Creek 500 kV overhead transmission line is part of the Surry – Skiffes Creek – Whealton project, which also includes the Skiffes Creek switching station, a new 230 kV line from Skiffes Creek to Whealton, and substation upgrades.

Per our Scope of Work, we evaluate alternatives only to the Surry – Skiffes Creek 500 kV overhead line (and the 500 kV portions of the switching station), and not to the other pieces of the overall project.
NERC Transmission Planning Standard

• Dominion Virginia Power plans transmission upgrades based upon the NERC Standard TPL-001-4, which has been in effect since October of 2013
• TPL-001-4 replaces NERC TPL-001-0, TPL-002-0, TPL-003-0 and TPL-004-0
• DVP often uses vocabulary from earlier standards in describing requirements for the Surry-Skiffes Creek project.
• Standard TPL-001-4 is not fully prescriptive. Each transmission owner (TO) has the ability to develop its own criteria to meet TPL-001-4, specifying, among other things, acceptable transmission facility limits

• TCR has based its analyses on the DVP Transmission Planning Criteria under NERC Standard TPL-001-4
Summary of Most Critical DVP Transmission Planning Criteria

• There are three categories of reliability requirements that drive the need for solutions in the North Hampton Roads Area (NHRA)
  • This is consistent with analysis reported by DVP (3/21/16 letter to NPCA and attachments)
  • Once these requirements are met, all other requirements are met also

• These requirements are to maintain power flows within the “Load Dump” limit of all transmission facilities that remain in service after pre-specified multi-element outages, as described in the table

• Dominion’s Planning Criteria are not specific about Extreme Events: “...more severe but less probable scenarios should also be considered. As permitted by NERC Planning Standards, judgment shall dictate whether and to what extent a mitigation plan would be appropriate.”*
  • In the analysis, we assume that the criteria for these events are similar to those for Categories P6-P7, except possibly for the amount of load loss required to return the flow on all facilities to acceptable levels (Short Term Emergency limits).


<table>
<thead>
<tr>
<th>Category</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Planning Event P6</td>
<td>Independent, sequential outage of two individual transmission facilities, with adjustments made after the first outage (also known as N-1-1)</td>
</tr>
<tr>
<td>Multiple Contingency</td>
<td></td>
</tr>
<tr>
<td>(two overlapping singles)</td>
<td></td>
</tr>
<tr>
<td>Planning Event P7</td>
<td>Loss of two adjacent circuits on a common structure (tower)</td>
</tr>
<tr>
<td>Multiple Contingency</td>
<td></td>
</tr>
<tr>
<td>(common structure)</td>
<td></td>
</tr>
<tr>
<td>Extreme Event</td>
<td>The most severe Extreme Event in the area is the simultaneous outage of all transmission facilities on a Right of Way</td>
</tr>
</tbody>
</table>
Available Data*

• Each utility that operates integrated transmission system facilities that are rated at or above 100 kV, must annually submit to the FERC the following information as part of its Form No. 715 - Annual Transmission Planning and Evaluation Report filings:
  • Power flows used in transmission planning efforts
  • Transmission planning criteria
  • Transmission system maps and diagrams

• PJM Interconnection publishes the model results that it has developed as part of the Regional Transmission Expansion Plan (RTEP) process, including the definition of each contingency used to model Planning Events to meet NERC Standards

* NTHP requested data from DVP. None was provided.
TCR performed the power flow simulations using PowerWorld Simulator Release 18
  • PowerWorld is an industry standard and is in the modeling toolbox of FERC and of PJM and most other system operators

• The power flow cases used in the analyses model a representative and wide range of years and system conditions included in the FERC Form No. 715 filings of DVP
  • 2016 Summer Peak
  • 2016 Winter Peak
  • 2016 Spring Minimum Load
  • 2021 Summer Peak
  • 2026 Summer Peak
Analysis Methodology

• Based on the power flow analysis summary tables provided by DVP to NPCA (letter dated March 21, 2016), TCR verified that violations to NERC Standard TPL-001-4 occurred in the absence of Surry – Skiffes Creek 500 kV, and identified and evaluated alternatives that would meet the Standard

• TCR used the power flows and other information filed by DVP in FERC Form No. 715, and the contingency definitions published by PJM as part of its RTEP model

  • Other than removal of Surry – Skiffes Creek 500 kV from the models, the power flow cases used in the TCR analyses are identical to those filed by DVP (e.g., TCR made no modifications to the load or generation profiles except as indicated in the Alternatives)

  • PJM does not include Extreme Contingencies in the PJM RTEP model. As such, TCR developed the Extreme Contingencies based on the letter from DVP to NPCA, other documents submitted as part of the Surry – Skiffes Creek proceeding, and engineering judgment
Main Drivers for Transmission Solutions in NHRA

Extreme Events and Tower Outages

• Without Yorktown and Surry – Skiffes Creek, the following single contingencies require mitigation:
  • Outage of all four lines in the Chickahominy – Lanexa Right of Way (Extreme Event)
  • Outage of all four lines in the Lanexa – Skiffes Creek Right of Way (Extreme Event)
  • Outage of the existing 230 kV James River crossing double circuit (tower contingency, Planning Event P7)
Main Drivers for Transmission Solutions in NHRA

Sequential Independent Outages (N-1-1: P6 Cat)

- Without Yorktown and Surry – Skiffes Creek, after the occurrence of any of the following single contingencies, there is a need to mitigate the next (potential) contingency:
  - Chickahominy – Skiffes Creek 230 kV
  - Lanexa – Skiffes Creek 230 kV
  - Surry – Winchester 230 kV
  - Chuckatuck – Newport News 230 kV

- Given that these are sequential events, per NERC Standard and DVP Criteria adjustments can be made after the occurrence of the first outage.

Source: PJM System Map
Alternative A – Reconductor and Reconfigure

- Reconductor existing 115 kV line Lanexa – Toano
- Energize existing 115 kV line Toano – Kings Mill*
- Reconductor existing 230 kV line Lightfoot – Kings Mill
- Energize existing 115 kV line Lanexa – Dow Tap (West end of line 34),* split the Skiffes Creek 115 kV so that line 34 is not connected to other facilities at Skiffes Creek, and de-energize 115 kV line Yorktown – Grafton (East end of line 34), after the outage of parallel 230 kV lines 209 or 285

* These are normally energized in operations, but are de-energized in the DVP power flow models filed with the FERC in 2016

Increase nominal import capacity from West of NHRA by 509 MW, to deal with N-1-1 and tower contingencies

Increase import capacity by another 54 MW after a major 230 kV outage

Source: PJM System Map
Alternative A – Dealing with Extreme Events

- Enable the generator at Yorktown 3 to run continuously as a synchronous condenser*
- Recondor 230 kV line Poolesville – Winchester
- Recondor 230 kV line Chackatuck – Shellbank

* Doing so does not preclude Yorktown 3 from generating on an as-needed basis.

Sustain voltage under worst contingencies and reduce MVAr flows

Increase import capacity from South East by 250 MW to meet Extreme (Right of Way) contingencies that outage most of the supply from the West
Alternative A – Reconductor and Reconfigure

- Reconductor 230 kV line Lightfoot – Kings Mill (section of line 209, ~9 miles) to increase its summer *Load Dump Rating* by 20% to 650 MVA
- Reconductor 115 kV line Lanexa – Toano (section of line 58, ~6.5 miles) to increase its summer *Load Dump Rating* by 20% to 200 MVA
- Enable the generator at Yorktown 3 to run continuously as a synchronous condenser
- Reconfigure the system under Summer Peak conditions:
  - Energize existing 115 kV line Toano – Kings Mill (section of line 58)
  - After the outage of line 209 or 285, energize 115 kV line Lanexa – Dow Tap (West end of line 34), de-energize 115 kV line Yorktown – Grafton (East end of line 34), and split the Skiffes Creek 115 kV so that line 34 is not connected to other facilities at Skiffes Creek
- Reconductor 230 kV line Chuckatuck – Newport News and Newport News – Shellbank (~18 miles in total) to increase its summer *Load Dump Rating* by 25% to 840 MVA and 686, respectively*
- Reconductor 230 kV line Poolesville – Winchester (~29 miles) to increase its summer *Load Dump Rating* by 12% to 750 MVA*

* Otherwise, develop SPS to shed 225 MW of load upon overload of 230 kV Benns Church – Copeland, and keep Yorktown 3 on stand-by (would only occur if one of two Extreme Right of Way contingencies occur, and would last until Yorktown 3 is started, up to 8-10 hours); see Alternative C*
Alternative B – Yorktown 3 On Summer Peak*

• Start and dispatch Yorktown 3 at 310 MW** (minimum load, per DVP letter to NPCA 9/12/16) under summer peak conditions
  • Under all other seasonal conditions analyzed (winter peak and spring minimum load), TCR identified no violations to NERC Standard TPL-001-4 or DVP Planning Criteria in the absence of Surry – Skiffes Creek 500 kV
  • Overhead lines in the NHPA area are predominantly thermally limited; with lower ambient temperatures, transmission capacity increases significantly
• Under the conservative assumption that summer peak conditions occur 5 days/week for 12 weeks per year, the annual capacity factor of Yorktown 3 would be 6.4% (well below the 8% limit under MATS; assumed a Yorktown 3 nominal capacity of 790 MW)

*The DVP IRP indicates that Yorktown 3 will be available at least through 2022. The 2026 Summer Peak power flow filed with FERC indicates that Yorktown 3 is available and dispatched at 630 MW in 2026.
** In the 2026 Summer Peak power flow case, Yorktown generation remains at 630 MW. Under outage conditions of Yorktown 3 in 2026, the generation shortfall is covered by starting Possum Point 5 (full output) and three of the Northern Neck units, and by shutting down two of the Gravel Neck units; in addition, the same transmission system reconfiguration specified under Alternative C is made.
**Alternative C – Yorktown 3 Stand-by**

Meet all N-1-1 contingencies (similar to Alternative B)

Voltage support

Increase nominal import capacity from West of NHRA by 272 MW, to deal with tower contingencies

Meet Extreme (ROW) Events

- Start and dispatch Yorktown 3 at 310 MW (minimum load, per DVP letter to NPCA 9/12/16) under summer peak conditions upon the occurrence of a critical single-element contingency (see previous slide that discusses the main N-1-1 contingency drivers)

- **Enable the generator at Yorktown 3 to run continuously as a synchronous condenser**

- Reconfigure the system under Summer Peak conditions (pre-contingency):
  - Energize existing 115 kV line Toano – Kings Mill (section of line 58)*
  - Energize 115 kV line Lanexa – Dow Tap (line 34),* and split the Skiffes Creek 115 kV so that line 34 is not connected to other facilities at Skiffes Creek

- Develop a Special Protection Scheme (SPS) to drop 225 MW of load at selected NHRA feeders upon overload of 230 kV Benns Church – Copeland (would only occur if one of two Extreme Right of Way contingencies occur; would last only until Yorktown 3 is started, estimated to be 8-10 hours)$^{1,2}$

* These are normally energized in operations, but are de-energized in the power flow models filed by DPV with FERC

1. *Dominion could implement this SPS by seeking fast-response contingency reserves from key large users or through other demand management alternatives*

2. *Otherwise, reconductor 230 kV lines Chuckatuck – Shellbank and Poolesville – Winchester; see Alternative A*
Alternative D – Bypassing Critical ROWs

- Tap existing 230 kV line (#2075) near Brookwoods
- Tap existing 230 kV line (#224) near Slaterville
- Build new 230 kV line between Brookwoods and Slaterville
- Reconductor/rebuild 230 kV line Lanexa – Slaterville
- Create parallel path to Chickahominy – Lanexa ROW to solve associated Extreme Event
- In conjunction with existing Lanexa – Harmony 230 kV line, create parallel path to Lanexa – Skiffes Creek ROW to solve associated Extreme Event and support N-1-1 events
- Build new 230 kV line between Hayes and Harmony
Alternative D – New 230 kV Paths

• Tap existing 230 kV line (#2075) near Brookwoods
• Tap existing 230 kV line (#224) near Slaterville
• Build new 230 kV line between Brookwoods and Slaterville (~18 miles, along I-64 or route 249)
• Build new 230 kV line between Hayes and Harmony (~25 miles, on existing right of way)
• Reconduct/rebuild 230 kV line Lanexa – Slaterville (~5.75 miles) to increase its summer Load Dump Rating by 40% to 620 MVA
• Enable the generator at Yorktown 3 to run continuously as a synchronous condenser
• Reconfigure the system under Summer Peak conditions:
  • Energize existing 115 kV line Toano – Kings Mill (section of line 58)
  • Energize 115 kV line Lanexa – Dow Tap (West end of line 34) and split the Skiffes Creek 115 kV so that line 34 is not connected to other facilities at Skiffes Creek
  • After the outage of line 285, de-energize line Chickahominy – Lanexa circuit 2
Summary of Proposed Alternatives

- TCR identified and fully evaluated four complementary, specific alternatives to the Surry-Skiffes proposed river crossing each of which meets all reliability requirements, is generally less costly and can be implemented in a shorter period of time.

<table>
<thead>
<tr>
<th>Alternatives</th>
<th>Estimated Cost</th>
<th>Estimated time frame</th>
</tr>
</thead>
<tbody>
<tr>
<td>A – Reconductor &amp; Reconfigure</td>
<td>$78 million</td>
<td>&lt; 12 months</td>
</tr>
<tr>
<td>B – Yorktown 3 online during Summer Peak</td>
<td>increased generation costs only*</td>
<td>Available today</td>
</tr>
<tr>
<td>C – Yorktown 3 Standby</td>
<td>$12 million</td>
<td>&lt; 12 months</td>
</tr>
<tr>
<td>D – Critical ROW Bypass</td>
<td>$72 - $132 million</td>
<td>&lt; 20 months</td>
</tr>
<tr>
<td>Overhead James River crossing</td>
<td>$100 million + $85 million (mitigation)</td>
<td>20 months</td>
</tr>
</tbody>
</table>

* Based on the revenue shortfall (fuel and other operation cost minus PJM energy market revenue) of operating Yorktown 3 for 12 weeks, 5 days/week, under July – September 2016 conditions, these are estimated at $12 million/year.
Richard D Tabors, Ph.D.
President
rtabors@tcr-us.com
617 871 6913

Tabors Caramanis Rudkevich
75 Park Plaza
Boston MA 02116
Richard D. Tabors, Ph.D. is an economist and scientist with 35 years of domestic and international experience in energy planning and pricing, international development, and water and wastewater systems planning. He is currently President and Principal of Tabors Caramanis Rudkevich, an energy, water and wastewater consulting group in Boston, and Visiting Scholar and co-director of the Utility of the Future Project at the MIT Energy Initiative. Prior to forming Tabors Caramanis Rudkevich he was president of Across the Charles. Dr. Tabors was Vice President of Charles River Associates from 2004 to 2012.

From 1976 until 2006 Dr. Tabors held a variety of position at Massachusetts Institute of Technology culminating in the title of Senior Research Engineer and Senior Lecturer. These positions involved research development and supervision as well as academic teaching and included being Assistant Director of the power systems engineering laboratory (LEES) and associated director of the Technology and Policy master’s program. Prior to MIT Dr. Tabors was Assistant Professor of City and Regional Planning and a member of the teaching faculty of the College of Arts & Sciences at Harvard University. At present he is a visiting professor of Electrical Engineering at the University of Strathclyde, Glasgow, Scotland where he was awarded an Honorary Doctorate in Engineering in July 2016.

Dr. Tabors was a member of the team at MIT that developed the theory of spot pricing (Spot Pricing of Electricity Kluwer Academic, 1989) upon which real-time pricing (RTP) and locational marginal pricing (LMP) of electricity and transmissions services are based. While still at MIT Dr. Tabors and coauthors Michael Caramanis & Roger Bohn formed Tabors Caramanis & Associates (1988) that was sold to Charles River Associates in 2004.
Dr. Tabors' research continues in the development and implementation of locational pricing in both the electricity and natural gas sectors. He currently leads an effort to design a platform-based market structure for the products and services provided by distributed electric energy resources (DERs).

Dr. Tabors provides expert assistance and testimony in regulatory and arbitration cases in the energy sector at the Federal, State and Provincial levels in North America and provides technical assistance in electricity markets and market development worldwide. His strength both in academia and in private practice is in the development and management of effective, research, client and problem focused teams that bring intellectual originality and rigor to the challenges of energy markets.
EXPERIENCE

2014-Present  President and Principal Tabors Caramanis Rudkevich, an Energy and Environmental Consulting Group, Boston, MA and Senior Consultant


2012–2014  President and Principal Across the Charles, Cambridge, MA

2004–2012  Vice President, Charles River Associates

- Co-director of Energy & Environment practice area.

2004–Present  Visiting Professor of Electrical Engineering, University of Strathclyde, Glasgow, Scotland

1986–2006  Senior Lecturer, Technology and Policy Program, Massachusetts Institute of Technology (MIT)


1989–1998  Lecturer, Department of Electrical Engineering and Computer Science, MIT

- "Introduction to Power Systems Operations and Planning."


1985–1998  Assistant Director, Laboratory for Electromagnetic and Electronic Systems, MIT

- Responsible for laboratory administration and research in power systems economics and planning, research on power systems monitoring and control, principal investigator on research program in performance based monitoring and control.

1990–1993  Principal Research Associate, MIT

- Co-Faculty “Planning for Water and Sewerage” and “Dealing with the Complete System,” MIT Summer Session.


1978-1988  Lecturer, Department of Urban Studies and Planning, MIT
1973-1988  Principal, Meta Systems

- utilities group in power systems planning, pricing and systems analysis

1985–1987  Faculty, Course 11.944, Department of Urban Studies and Planning (co-taught as KSG S115 with P. Rogers) “Energy Sector Planning in Developing Countries.”

1971–1976  Research Associate and Member, Center for Population Studies, Harvard University

- Research on resource and environmental planning in developing nations of South Asia and Africa.

1978–1984  Program Manager, Utility Systems, MIT Energy Laboratory

- Economic and systems research and development in electric and gas utility systems; including the integration of new generation systems (photovoltaics) into the grid.

1979-1983  Project Manager and Principal Investigator, Electric Generation Expansion Analysis System (EGEAS) Project, under contract to EPRI, MIT Energy Laboratory.


1976-1977  Economist, Photovoltaics Project, MIT Energy Laboratory and Lincoln Laboratory.


1974-1976  Assistant Professor of City and Regional Planning, Harvard University.

1973-1976  Research Fellow, Environmental Systems Program, Division of Engineering and Applied Physics, Harvard University.


1973-1974  Lecturer on City and Regional Planning, Graduate School of Design, Harvard University.

1971  Resident Representative, Harvard University, East Pakistan (Bangladesh) Land, Water and Power System Study, Dacca, East Pakistan.

1970  Graduate Administrative and Teaching Assistant to A. K. Campbell, Dean, Maxwell Graduate School of Citizenship and Public Affairs, Syracuse University.

- Informal advisor on Regional Economic Planning to the Urban Development Directorate, Planning Department, Government of East Pakistan (Bangladesh).

**CONSULTING EXPERIENCE**

- For integrated market participant in Canada, provided due diligence in evaluation of electricity market structure.

- For merchant transmission developer, provides project financial and development assistance in technology and site selection (2013 – Present)

- For multiple private power development groups, provides project valuation for generation and transmission. (2000 – Present)

- For the City of New York provided technical and analytic support in the evaluation of the possible closing of the Indian Point Nuclear Generating Station including analysis of the impact of the Fukushima Nuclear accident (2011)

- Provided technical and economic strategy and regulatory assistance to off-shore wind developer (2009 – Present)

- In cooperation with Merrill Energy, provide expert advice on implementation of legislation to recover capital cost of transmission investment in Peru. (2010)

- Direct and provide consulting advice to the Federal Electricity & Water Authority in the United Arab Emirates on corporate reorganization. (2007-2011)

- Provide expert testimony to major US independent power producer in arbitration with steam host. (2007 – 2009)

- Direct and provide expert services and consulting advice to Electricite du Liban on revenue recovery through development of AMI systems. (2006 – 2008)

- Direct and provide consulting services to Electricite du Liban on restructuring of distribution services. (2006 – 2008)


- Provide expert analytic assistance to Private Equity Fund on purchase of generation assets within the United States (2006- 2007).

- Member, Board of Directors, NeuCo Corporation. (2005 - 2012)
• Direct and provide consulting services to Abu Dhabi Water and Electricity Authority on distribution system performance. (2003–2005)

• Direct and provide expert testimony on the development of the MidWest Independent System Operator. (2002–Present)

• Direct and provide expert testimony on long-term contract market in California. (2002–Present)

• Direct and provide expert testimony in purchase, contracting and regulatory approval of Midwestern transmission system. (2002–2003)

• Direct and provide expert testimony in 9-billion dollar California Electric refund case (2001–2012)

• Direct and provide expert testimony and consulting to major U.S. market and generator in the redesign of the California electricity market. (2002–2010)

• Member of the Blue Ribbon Task Force on design of electricity auctions of the California Power Exchange with Alfred Kahn, Peter Cramton and Robert Porter. (2000–2001)

• Member, Board of Directors of Dynamic Knowledge Corporation, Glasgow, Scotland. (2001–Present)

• Consultant to more than 20 power development companies for evaluation of locational value of new generation and transmission. (1999–Present)

• Consultant to and member of Technology Advisory Board, Excelergy Corporation, development of utility billing and system auction software. (1999–2002)

• Consultant to a Midwest utility for development of transmission congestion pricing structure. (1999–2001)

• Consultant to transmission asset development team of major U.S. corporation. (1999–2000)


• Consultant to major U.S. paper manufacturer for federal regulatory change required to interconnect a new co-generation facility. (1998–2000)

• Consultant to major Midwest utility in the development of an independent transmission company and the required tariffs. (1998–2002)


• Consultant to the Department of the Attorney General, State of Rhode Island and Providence Plantation for electric utility industry restructuring. (1996–1997)


• Consultant to ABB/Systems Control on transmission pricing and power systems operations. (1994–1997)

• Consultant to a major western utility for the development of transmission pricing strategies. (1994–1996)


• Consultant on the background to electric industry restructuring to Central Vermont Public Service. (1995)

• Development of real-time pricing rate response experiments for NYSERDA, EPRI and ESSERCo in ConEd and NYSEG service territories: Response to real-time pricing. (1989–1994)

• Development of marginal, cost-based, transmission system pricing system for the National Grid Company (NGC) of the United Kingdom. (1991–1993)


• Development of purchase and transmission strategy for major U.S. independent power producer. (1990)


Variable energy cost/spot pricing studies under contract to Integrated Communications Systems of Atlanta. Utilities included Mid-South and Pacific Gas and Electric, Southern California Edison, Central and South West. (1984-1987)


Value of reliability study for Public Service of New Mexico. (1984)

With East-West Center, Honolulu, Hawaii, study of electric futures of northeast Asia, Japan, Korea and Taiwan. (1983–1984)


Lignite pricing for electric power generation, Thailand. For IBRD (1982–1983)

Independent, review of electric power futures for combustion engineering. (1982)


Consultant, Urban Systems Research and Engineering. Projects included: Analysis of Boston wastewater management plan for C.E.Q.; definition of 'modal' urban areas for environmental impact analysis using the EPA developed SPACE/SEAS model; Interceptor project to evaluate the impact of EPA interceptor grants program or land use patterns in suburban and rural areas of EPA Regions 2, 4, 6; Rural growth project analyzing regional development in non-metropolitan multi-county areas in the United States. (1971–1977)

Urban systems research and engineering analysis of Boston wastewater management plan for C.E.Q. (1977)

Bangladesh energy study for Asian Development Bank and UNDP. (1975–1976)

Urban systems research and engineering, definition of model urban areas for environmental impact analysis using the EPA developed SPACE/SEAS model. (1975–1976)


• Lake Chad polder development study of agricultural development with low-lift irrigation pumping in the area immediately surrounding Lake Chad. (1974)

• Urban systems research and engineering, interceptor sewer project to evaluate the impact of EPA interceptor grants program on land use patterns in suburban and rural areas of EPA Regions, 2,4,6. (1974)


FIELDS OF EXPERTISE

• Energy economics / energy pricing

• Power systems operations and planning

• Asset valuation: Generation, Transmission and Generation

• Water and wastewater management

• Corporate strategic planning and analysis

• Corporate reorganization and management

PROFESSIONAL AFFILIATIONS

• Institute of Electrical and Electronic Engineers

• American Waterworks Association

• International Association of Energy Economists

• Energy Bar Association

REGULATORY COMMENT AND TESTIMONY

• “Economics and Integration of Photovoltaic System into the Utility Grid,” to Senate Committee Staff on Science and Technology, September 1981.


• Expert Witness, St. Peter, MN vs. SMMPA, Utility Planning and Forecasting, 1986.


• Testimony before the California Public Utility Commission en banc hearings on industry restructuring, September, 1994 sponsored by Enron Capital and Trade Resources.

• Testimony before the Massachusetts Public Utility Commission hearings on industry restructuring, April, 1995 sponsored by Enron Capital and Trade Resources.


• Testimony before the New York Public Service Commission on Two Party Transactions Proposal of NYPSC, Docket No. 96-E-0798, 1996.


• Testimony before the state of Rhode Island and Providence Plantations Public Utility Commission on Electric Industry Restructuring and Market Power sponsored by the Attorney General, State of Rhode Island, Docket No. 2320, April 1996.

• Testimony before the Commonwealth of Massachusetts, Department of Public Utilities in Panel Format on The Independent System Operator / NEPOOL / FERC Order No. 888 and on the Power Exchange.


• Testimony before the State of Maryland Public Service Commission on Restructuring, August 1997.

• Testimony before the Pennsylvania Public Utilities Commission on Capacity Benefit Margin, 1998.

• Testimony before the Public Service Commission of Wisconsin, Investigation on the Commission’s Own Motion Into the Development of an Independent System Operator for the Electric Transmission System of Wisconsin (05-BE-100), April 1998.


• Testimony before the Alberta Energy and Utilities Board in regards to ESBI Alberta Ltd.’s General Rate Application, Phase II, 1999/2000, on transmission tariff design and cost allocation mechanisms.


• Testimony before the Federal Energy Regulatory Commission on behalf of Powerex Corporation and the Transaction Finality Group on Ripple Effects of proposed Pacific Northwest refunds, Hydro operations in the Pacific Northwest and proposed price mitigation in the Pacific Northwest, Docket Nos. EL01-10-000; EL01-10-001, August 28, 2001.

• Testimony before the Federal Energy Regulatory Commission on behalf of Powerex Corporation and the Transaction Finality Group on the need for price mitigation in the Pacific Northwest, Docket Nos. EL01-10-000; EL01-10-001, October 29, 2001.

• Testimony before the Federal Energy Regulatory Commission on behalf of the Electric Power Supply Association (EPSA) regarding Market Based Rates, docket EL01-118-000, January 2002.

• Testimony before the Federal Energy Regulatory Commission on behalf of Dynegy Power Marketing, et al on Market Power Mitigation rules within MD02 proposal of California ISO, Docket Nos. EL00-95-001; ER02-1656-000, June 2002.

- Testimony before the Federal Energy Regulatory Commission on behalf of Dynegy Corporation on Long-Term Contracts in California; Docket Nos. EL02-6—000; EL02-62-000, October 17, 2002, November 14, 2002.

- Testimony before Arbiter in Portland Oregon on behalf of Powerex against Alcan on the termination of a supply contract. November, 2002


- Testimony before the Federal Energy Regulatory Commission on behalf or Portland General Electric regarding Circular Schedules or Death Star Transactions, Docket Nos. EL02-114-000 and EL-02-115-001, February 24, 2003.


- Testimony before the Federal Energy Regulatory Authority on behalf of Portland General Electric Company in defense of accusation market manipulation (EL02-114-000 and EL02-115-001), 2004.

- Testimony before Arbitration Panel in Bankruptcy Liberty Generating Station, Philadelphia on behalf of National Energy Group, 2005.

- Testimony before the Federal Energy Regulatory Authority on behalf Constellation Energy Commodities group, Inc. in support of cost and revenue studies, 2005.


- Testimony before the Kansas Public Utility Commission in support of the expansion of transmission facilities in Kansas in support of Westar Corporation. 2009 and 2010.

- Testimony before the Federal Energy Regulatory Commission (ER 10-1138) on behalf of Northwestern Energies, June 2012

- Testimony before the Federal Energy Regulatory Commission on behalf of NEPOOL (ER13-895-000) in opposition to changes in market timing rules related to acquisition of natural gas. (with Seabron Adamson)


- Expert Reports and Testimony before the FERC Enforcement Bureau for multiple clients accused of market manipulation of US organized power markets (Ongoing)

- Testimony before the Ohio Public Utility Commission on behalf of First Energy Solutions in opposition to proposed tariff changes by Duke Energy Ohio. April 2013.

- Testimony before the Federal Energy Regulatory Commission on behalf of NEPOOL (ER14-1050-000 / 001) in opposition to proposed Incentive Payment proposal changes in FCM rules. (2014-2015)

- Testimony before the Maryland Public Service Commission on behalf of the State of Maryland and the Maryland Energy Administration in the matter of the merger of Exelon Corporation and PEPCO Holding, Inc, (Case No. 9361) 2014 -2015.

Filed before the United State Supreme Court


- Signed as Amicus in Amicus Curiae of Leading Economists and Educators who have Designed, Studied, Taught and Written about Electricity Markets in support of the Court in No. 11-1486, Electric power Supply Association, et al, v Federal Energy Regulatory Commission, et al. June 2012

**Publications**

**Books, Book Chapters, and Monographs**


**Articles and Reviews**


“The Role of Demand Underscheduling in the California Energy Crisis.” With E.D. Hausman. 


**Technical Reports**


“White Paper on Developing Competitive Electricity Markets and Pricing Structures” with G. Parker, P. Centolella and M. Caramanis, Prepared for the New York State Energy Research and Development Authority (NYSERDA) and New York State Department of Public Service, December, 2015.

Working Papers and Discussion Papers


“Economics and Integration of Photovoltaic System into the Utility Grid.” To Senate Committee Staff on Science and Technology, September 1981.


You can help protect America’s National Treasures

Visit SavingPlaces.org

The National Trust for Historic Preservation, a privately funded nonprofit organization, works to save America’s historic places.