EXHIBIT JAL/CDF-1

Dr. Jonathan A. Lesser Curriculum Vitae

Jonathan A. Lesser, Ph.D.
President

SUMMARY OF EXPERIENCE

Dr. Jonathan Lesser is the President of Continental Economics, Inc., and has 30 years of experience working for regulated utilities, governments, and as an economic consultant. He has extensive experience in valuation and damages analysis, from estimating the damages associated with breaking commercial leases to valuing nuclear power plants. Dr. Lesser has performed due diligence studies for investment banks, testified on generating plant stranded costs, assessed damages in commercial litigation cases, and performed statistical analysis for class certification. He has also served as an arbiter in commercial damages proceedings.

He has analyzed economic and regulatory issues affecting the energy industry, including cost-benefit analysis of transmission, generation, and distribution investment, gas and electric utility structure and operations, generating asset valuation under uncertainty, mergers and acquisitions, cost allocation and rate design, resource investment decision strategies, utility financing and the cost of capital, depreciation, risk management, incentive regulation, economic impact studies of energy infrastructure development, and general regulatory policy.

Dr. Lesser has prepared expert testimony and reports in cases before utility commissions in numerous US states; before the US Federal Energy Regulatory Commission (FERC); before international regulators in Latin America and the Caribbean; and in commercial litigation cases. He has also testified before the U.S. Congress, and legislative committees in numerous states on energy policy and market issues. Dr. Lesser has also served as an independent arbiter in disputes involving regulatory treatment of utilities and valuation of energy generation assets.

Dr. Lesser is the author of numerous academic and trade press articles. He is the coauthor of *Environmental Economics and Policy* (1997), *Principles of Utility Corporate Finance* (2011), and *Fundamentals of Energy Regulation* (2007; 2d ed., 2013). He is also a contributing columnist and Editorial Board member for *Natural Gas & Electricity*. Dr. Lesser is currently serving a three-year term as one of the Energy Bar Association "Deans" overseeing education programs on regulatory and ratemaking concepts.

AREAS OF EXPERTISE

- State, federal, and international electric rate regulation—cost of capital, depreciation, cost of service, cost allocation, pricing and rate design, incentive regulation, regulatory policy, wholesale and retail market design, and industry restructuring
- Commercial damages estimation and litigation
- Natural gas and oil pipeline rate regulation
- Natural gas markets
- Cost-benefit analysis
- Economic impact analysis and input-output studies
- Environmental policy and analysis
- Market power analysis
- Load forecasting and energy market modeling
- Market valuation and due diligence
- Antitrust

EDUCATION

- PhD, Economics, University of Washington, 1989
- MA, Economics, University of Washington, 1982
- BSc, Mathematics and Economics (with honors), University of New Mexico, 1980

EMPLOYMENT HISTORY

- 2009–Present: Continental Economics, Inc., President.
- 2004–2009: Bates White, LLC, Partner, Energy Practice.
- 2003–2004: Vermont Dept. of Public Service, Director of Planning.
- 1998–2003: Navigant Consulting, Senior Managing Economist.
- 1996–1998: Adjunct Lecturer, School of Business, University of Vermont.
- 1993–1998: Green Mountain Power Corporation, Manager, Economic Analysis.
- 1990–1993: Adjunct Lecturer, Dept. of Business and Economics, Saint Martin's College.

- 1986–1993: Washington State Energy Office, Energy Policy Specialist.
- 1984–1986: Pacific Northwest Utilities Conference Committee, Energy Economist.
- 1983–1984: Idaho Power Corporation, Load Forecasting Analyst.

SELECTED EXPERT TESTIMONY AND REPORTS

Utah Industrial Energy Consumers

- Proceeding before the Utah Public Service Commission Docket Nos. 13-035-184 and 13-034-196 (revenue requirement, cost allocation, and design of back-up service rates)

Paiute Pipeline Company

- FERC rate proceeding (*Re: Paiute Pipeline Company,* Docket No. RP14-540-000)

  Subject: Natural gas supplies and depreciation rates for transmission, storage, and general plant accounts.

Energy Michigan

- Proceeding before the Michigan Public Utilities Commission (*Re: Consumers Energy Corporation*, Case No. U-17429)

  Subject: Certificate of Convenience and Necessity for Consumers Power combined-cycle generating plant.

Constellation New Energy Inc. and Exelon Generation Company, LLC

- Proceeding before the Ohio Public Utilities Commission (*Re: Columbus Southern Power Company and Ohio Power Company*, Case Nos. 12-3254-EL-UNC)

  Subject: Design of competitive auction process and rate blending for AEP Ohio.

Shell Energy North America, LP

- FERC proceeding regarding natural gas pipeline fuel cost allocation (*Re: Rockies Express Pipeline, LLC,* Docket Nos. RP11-1844-000 & RP12-399-000)

Subject: Economic appropriateness of roll-in treatment of “lost and unaccountable” fuel

New York Association of Public Utilities

- FERC proceeding regarding formula transmission rate for Niagara Mohawk Power d/b/a National Grid (*Niagara Mohawk Power Co*., Docket No.

- FERC proceeding regarding formula transmission rate for Niagara Mohawk Power d/b/a National Grid (*Niagara Mohawk Power Co*., Docket No. EL12-101-000)

  Subject: Allowed rate of return and capital structure

Caribbean Utilities Company, Ltd.

- Rebuttal report on weighted average cost of capital methodology and recommendations for Caribbean Utilities Company, Ltd.

Utah Industrial Energy Users Coalition

- Proceeding before the Utah Public Service Commission (*Re: Rocky Mountain Power Corp*., Case No. U-11035-200)

  Subject: Appropriate methodology for embedded cost allocation for Rocky Mountain Power.

FirstEnergy Solutions Corp.

- Proceeding before the Ohio Public Utilities Commission (Case Nos. 12-2400-EL-UNC)

  Subject: Just and reasonableness of Duke Energy Ohio cost-recovery mechanism for capacity resources.

- Proceeding before the Ohio Public Utilities Commission (Case Nos. 12-426-EL-SSO)

  Subject: Dayton Power & Light Co., Electric Security Plan; financial integrity, anticompetitive cross-subsidization and need for structural separation

- Proceeding before the Michigan Public Service Commission (Case No. U-17032)

  Subject: Indiana & Michigan Power Co. proposed capacity charges for customers taking retail electric service.

- Proceeding before the Ohio Public Utilities Commission (Case Nos. 11-346-EL-SSO and 11-348-EL-SSO)

  Subject: Revised AEP Ohio energy security plan, benefits of retail market competition.

- Proceeding before the Ohio Public Utilities Commission (Case No. 10-2929-EL-UNC)

  Subject: Appropriate price for commercial retail electric suppliers to be charged by AEP Ohio for installed capacity under the PJM Fixed Resource Requirement tariff option.

Southwestern Electric Cooperative

- FERC proceeding regarding wholesale distribution rate application of Ameren Illinois (*Re: Midwestern ISO and Ameren Illinois*, Docket No. ER11-2777-002, et al.)

  Subject: Allowed rate of return and capital structure

Exelon Corporation

- Proceeding before the New Jersey Board of Public Utilities (Docket No. EO-11050309)

  Subject: PJM Capacity Market, Capacity Procurement, and Transmission Planning

Industrial Energy Users of Ohio

- Proceeding before the Ohio Public Utilities Commission (Case No. 08-917-EL-SSO)

  Subject: Determination of cost associated with “provider-of-last-resort” (POLR) service and AEP Ohio’s use of option pricing models.

Southwest Gas Corporation

- FERC proceeding regarding rate application of El Paso Natural Gas Company (Docket No. RP10-1398-000)

  Subject: Development of risk-sharing methodology for unsubscribed and discount capacity costs.

Portland Natural Gas Shippers

- FERC rate proceeding regarding the rate application by Northern Border Pipeline Company (Re: Portland Natural Gas Transmission System, Docket No. RP10-729-000)

- FERC rate proceeding regarding the rate application by Northern Border Pipeline Company (Re: Portland Natural Gas Transmission System, Docket No. RP08-306-000)

  Subject: Natural gas supplies, economic lifetime, and depreciation rates.

Independent Power Producers of New York

- FERC proceeding (New York Independent System Operator, Inc., Docket No. ER11-2224-000)

  Subject: Reasonableness of the proposed installed capacity demand curves and cost of new entry values proposed by the New York Independent System Operator.

Maryland Public Service Commission

- Merger application of FirstEnergy Corporation and Allegheny Energy, Inc. (I/M/O FirstEnergy Corp and Allegheny Energy, Inc., Case No. 9233)

  Subject: Proposed merger between FirstEnergy Corporation and Allegheny Energy. Testimony described the structure and results of a cost-benefit analysis to determine whether the proposed merger met the state's positive benefits test, and included analysis of market power and merger synergies.

Alliance to Protect Nantucket Sound

- Proceeding before the Massachusetts Department of Public Utilities (Case No. D.P.U. 10-54)

  Subject: Approval of Proposed Long-Term Contracts for Renewable Energy With Cape Wind Associates, LLC.

Brookfield Energy Marketing, LLC

- FERC proceeding (*New England Power Generators Association, et al. v. ISO New England, Inc.,* Docket Nos. ER10-787-000, ER10-50-000, and EL10-57-000 (consolidated)).

Subject: Proposed forward capacity market payments for imported capacity into ISO-NE.

Public Service Company of New Mexico

- Proceeding before the New Mexico Public Regulation Commission (Case No. 10-00086-UT)

  Subject: Load forecast for future test year, residential price elasticity study.

M-S-R Public Power Agency

- FERC proceeding (*Southern California Edison Co.*, Docket No. ER09-187-000 and ER10-160-000)

  Subject: Allowed rate of return for construction work in progress (CWIP) expenditures for certain transmission facilities.

- FERC proceeding (*Southern California Edison Co.*, Docket No. ER10-160-000)

  Subject: Allowed rate of return for construction work in progress (CWIP) expenditures for certain transmission facilities.

Financial Marketers

- FERC proceeding (*Black Oak Energy, LLC v PJM Interconnection, L.L.C.*, Docket No. EL08-014-002)

  Subject: Allocation of surplus transmission line losses under the PJM tariff.

Southwest Gas Corporation and Salt River Project

- FERC proceeding regarding rate application of El Paso Natural Gas Company (Docket No. RP08-426-000)

  Subject: Analysis of proposed capital structure and recommended capital structure adjustments

New York Regional Interconnect, Inc.

- Proceeding before the New York Public Service Commission (Case No. 06-T-0650)

Subject: Analysis of economic and public policy benefits of a proposed high-voltage transmission line.

Occidental Chemical Corporation

- FERC Proceeding (*Westar Energy, Inc.* ER07-1344-000)

  Subject: Compliance of wholesale power sales agreement with FERC standards

EPIC Merchant Energy, LLC, et al.

- FERC Proceeding (*Ameren Services Company v. Midwest Independent System Operator, Inc.,* Docket Nos. EL07-86-000, EL07-88-000, EL07-92-000 (Consolidated)

  Subject: Allocation of revenue sufficiency guarantee costs.

Cottonwood Energy, LP

- Proceeding before the Public Utility Commission of Texas (*Application of Kelson Transmission Company, LLC for a Certificate of Convenience and Necessity for the Amended Proposed Canal to Deweyville 345 kV Transmission Line with Chambers, Hardin, Jasper, Jefferson, Liberty, Newton, and Orange Counties*, Docket No. 34611, SOAH Docket No. 473-08-3341)

  Subject: Benefits of transmission capacity investments.

Redbud Energy, LP

- Proceeding before the Oklahoma Corporation Commission (*Request of Public Service Company of Oklahoma for the Oklahoma Corporation Commission to Retain an Independent Evaluator,* Cause No. PUD 200700418)

  Subject: Reasonableness of PSO's 2008 RFP design.

The NRG Companies

- FERC Proceeding (*ISO New England Inc. and New England Power Pool,* Docket No. ER08-1209-000)

  Subject: Compensation of Rejected De-list Bids Under ISO-NE's Forward Capacity Market Design

Dynegy Power Marketing, LLC

- FERC proceeding, *KeySpan-Ravenswood, LLC v. New York Independent System Operator, Inc.*, Docket No. EL05-17-000

  Subject: Estimation of damages accruing to Dynegy arising from a failure by the NYISO to accurately calculate locational installed capacity requirements in NYISO during the summer of 2002.

Constellation Energy Group

- FERC proceeding (*Maryland Public Utility Commission, et al., v. PJM Interconnection, LLC*, Docket No. EL08-67-000)

  Subject: "Just and reasonableness" of PJM's Reliability Pricing Mechanism.

Government of Belize, Public Utility Commission

- Proceeding before the Belize Public Utility Commission, *In the Matter of the Public Utilities Commission Initial Decision in the 2008 Annual Review Proceeding for Belize Electricity Limited.*

  Subject: Arbitration and Independent Expert's report, in dispute between the Belize PUC and Belize Electricity Limited in an annual electric rate tariff review, as required under Belize law.

Federal Energy Regulatory Commission

- Technical hearings on wholesale electric capacity market design.

  Subject: Analysis of proposal to revise RTO capacity market design developed by the American Forest and Paper Association.

Dogwood Energy, LLC

- Proceeding before the Missouri Public Service Commission, *In the Matter of the Application of Aquila, Inc., d/b/a Aquila Networks - MPS and Aquila Case No. EO-2008-0046, Networks - L&P for Authority to Transfer Operational Control of Certain Transmission Assets to the Midwest Independent Transmission System Operator, Inc.*, Case No. EO-2008-0046.

  Subject: Cost-benefit analysis to determine whether Aquila should join either the Midwest Independent System Operator (MISO) or the Southwest Power Pool (SPP).

Independent Power Producers of New York

- FERC proceeding (*Re: New York Independent System Operator, Inc.*, Docket No. ER08-283-000)

  Subject: Revisions to the installed capacity (ICAP) market demand curves in the New York control area, which are designed to provide economic incentives for new generation development.

Empresa Eléctrica de Guatemala

- Rate proceeding before the Comisión Nacional de Energía Eléctrica

  Subject: Rate of return for an electric distribution company

Electric Power Supply Association

- FERC proceeding (*Re: Midwest Independent Transmission System Operator, Inc.*, Docket No. ER07-1182-000)

  Subject: Critique of cost-benefit analysis by MISO Independent Market Monitor concluding that permanent establishment of Broad Constrained Area mitigation was appropriate.

Constellation Energy Commodities Group, LLC

- FERC proceeding regarding rate application for ancillary services by Ameren Energy (*Re: Ameren Energy Marketing Company and Ameren Energy, Inc.*, Docket Nos. ER07-169-000 and ER07-170-000)
- Subject: Analysis and testimony on appropriate "opportunity cost" rates for ancillary services, including regulation service and spinning reserve service. Case settled prior to testimony being filed.

Suiza Dairy Corporation

- Rate proceeding before the Office of Milk Industry Regulatory Administration of Puerto Rico.
- Subject: Analysis and testimony on the appropriate rate of return for regulated milk processors in the Commonwealth of Puerto Rico.

IGI Resources, LLC and BP Canada Energy Marketing Corp.

- FERC proceeding regarding the rate application by Gas Transmission Northwest Corporation (*Re: Gas Transmission Northwest*, Docket No. RP06-407-000)

Subject: Natural gas supplies, economic lifetime, and depreciation rates.

Baltimore Gas and Electric Co.

- Maryland Public Service Commission (Case No. 9099)

  Subject: Standard Offer Service pricing. Testimony focused on factors driving electric price increases since 1999, and estimates of rates under continued regulation

- Maryland Public Service Commission (Case No. 9073)

  Subject: Stranded costs of generation. Testimony focused on analysis of benefits of competitive wholesale power industry.

- Maryland Public Service Commission (Case No. 9063)

  Subject: Optimal structure of Maryland's electric industry. Testimony focused on the benefits of competitive wholesale electric markets. Presented independent estimates of the benefits of restructuring since 1999.

Pemex-Gas y Petroquímica Básica

- Expert report in a rate proceeding. Presented analysis before the Comisión Reguladora de Energía on the appropriate rate of return for the natural gas pipeline industry.

BP Canada Marketing Corp.

- FERC proceeding regarding the rate application by Northern Border Pipeline Company (*Re: Northern Border Pipeline*, Docket No. RP06-072-000)

  Subject: Natural gas supplies, economic lifetime, and depreciation rates.

Transmission Agency of Northern California

- FERC rate proceeding (*Re: Pacific Gas & Electric Company*, Docket No. ER09-1521-000)

  Subject: Analysis of appropriate return on equity, capital structure, and overall cost of capital. Case settled prior to filing expert testimony.

- FERC rate proceeding (*Re: Pacific Gas & Electric Company*, Docket No. ER08-1318-000)

  Subject: Analysis of appropriate return on equity, capital structure, and overall cost of capital. Case settled prior to filing expert testimony.

- FERC rate proceeding (*Re: Pacific Gas & Electric Company*, Docket No. ER07-1213-000)

  Subject: Analysis of appropriate return on equity, capital structure, and overall cost of capital. Case settled prior to filing expert testimony.

- FERC rate proceeding (*Re: Pacific Gas & Electric Company*, Docket No. ER06-1325-000)

  Subject: Analysis of appropriate return on equity, capital structure, and overall cost of capital. Case settled prior to filing expert testimony.

- FERC rate proceeding (*Re: Pacific Gas & Electric Company*, Docket No. ER05-1284-000)

  Subject: Analysis of appropriate return on equity, capital structure, and overall cost of capital. Case settled prior to filing expert testimony.

- FERC rate proceeding (*Re: Pacific Gas & Electric Company*, Docket Nos. ER03-409-000, ER03-666-000)

  Subject: Analysis and development of recommendation for the appropriate return on equity, capital structure, and overall cost of capital.

State of New Jersey Board of Public Utilities

- Merger application of Public Service Enterprise Group and Exelon Corporation (*I/M/O The Joint Petition Of Public Service Electric And Gas Company And Exelon Corporation For Approval Of A Change In Control Of Public Service Electric And Gas Company And Related Authorizations, BPU Docket No. EM05020106, OAL Docket No. PUC-1874-050*)

  Subject: Proposed merger between Exelon Corporation and PSEG Corporation. Testimony described the structure and results of a cost-benefit analysis to determine whether the proposed merger met the state's positive benefits test, and included analysis of market power, value of changes in nuclear plant operations, and merger synergies.

Sierra Pacific Power Corp.

- FERC proceeding regarding the rate application by Paiute Pipeline Company (*Re Paiute Pipeline Company* Docket No. RP05-163-000)

  Subject: Depreciation analysis, negative salvage, and natural gas supplies. Case settled prior to filing expert testimony.

Matanuska Electric

- Regulatory Commission of Alaska rate proceeding (*In the Matter of the Revision to Current Depreciation Rates Filed by Chugach Electric Association, Inc.*, Docket No. U-04-102)

  Subject: Analysis of the reasonableness of Chugach electric's depreciation study.

Duke Energy North America, LLC

- FERC proceeding (*Re: Devon Power, LLC*, et al., Docket No. ER03-563-030)

  Subject: Appropriate market design for locational installed generating capacity in the New England market to ensure system reliability.

Keyspan-Ravenswood, LLC

- FERC proceeding, *KeySpan-Ravenswood, LLC v. New York Independent System Operator, Inc.*, Docket No. EL05-17-000

  Subject: Estimation of damages arising from a failure by the NYISO to accurately calculate locational installed capacity requirements in New York City during the summer of 2002.

Electric Power Supply Association

- FERC proceeding (*Re: PJM Interconnection, LLC*, Docket No. EL03-236-002)

  Subject: Analysis and critique of proposed pivotal supplier tests for market power in PJM identified load pockets.

Vermont Department of Public Service

- Vermont Public Service Board Rate Proceedings
    - Concurrent proceedings: *Re: Green Mountain Power Corp.*, Dockets No. 7175 and 7176. Subject: Cost of capital and allowed return on equity under cost of service regulation, as well as under a proposed alternative regulation proposal.
    - *Re: Shoreham Telephone Company*, Docket No. 6914. Subject: Analysis and development of recommendations for the appropriate return on equity, capital structure, and overall cost of capital.
    - *Re: Vermont Electric Power Company*, Docket No. 6860. Subject: Development of a least-cost transmission system investment strategy to

analyze the prudence of a major high-voltage transmission system upgrade proposed by the Vermont Electric Power Company.

- *Re: Central Vermont Public Service Company*, Docket No. 6867. Subject: Analysis and development of recommendations for the appropriate return on equity, capital structure, and overall cost of capital.
- *Re: Green Mountain Power Corporation*, Docket No. 6866. Subject: Analysis and development of recommendations for the appropriate return on equity, capital structure, and overall cost of capital.

Pipeline shippers

- FERC proceeding regarding the rate application of Northern Natural Gas Company (*Re: Northern Natural Gas Company*, Docket No. RP03-398-000)

  Subject: Gas supply analysis to determine pipeline depreciation rates as part of an overall rate proceeding.

Arkansas Oklahoma Gas Corp.

- Oklahoma Corporation Commission rate proceeding (*Re: Arkansas Oklahoma Gas Corporation*, Docket No. 03-088)

  Subject: Analysis and development of recommendations for the appropriate return on equity, capital structure, and overall cost of capital.

- Arkansas Public Service Commission rate proceedings
  - *In the Matter of the Application of Arkansas Oklahoma Gas Corporation for a General Change in Rates and Tariffs*, Docket No. 05-006-U. Subject: Analysis and development of recommendations for the appropriate return on equity, capital structure, and overall cost of capital.
  - *In the Matter of the Application of Arkansas Oklahoma Gas Corporation for a General Change in Rates and Tariffs*, Docket No. 02-24-U. Subject: Analysis and development of recommendations for the appropriate return on equity, capital structure, and overall cost of capital.

Entergy Nuclear Vermont Yankee, LLC

- Vermont Public Service Board proceeding (*Re: Petition of Entergy Nuclear Vermont Yankee for a Certificate of Public Good*, Docket No. 6812)

  Subject: Analysis of the economic benefits of nuclear plant generating capacity expansion as required for an application for a Certificate of Public Good.

Central Illinois Lighting Company

- Illinois Commerce Commission rate proceeding (*Re: Central Illinois Lighting Company*, Docket No. 02-0837)

  Subject: Analysis and development of recommendations for the appropriate return on equity, capital structure, and overall cost of capital.

Citizens Utilities Corp.

- Vermont Public Service Board rate proceeding (*Tariff Filing of Citizens Communications Company requesting a rate increase in the amount of 40.02% to take effect December 15, 2001*, Docket No. 6596)

  Subject: Analysis of the prudence and economic used-and-usefulness of Citizens' long-term purchase of generation from Hydro Quebec, including the estimated environmental costs and benefits of the purchase.

Dynegy LNG Production, LP

- FERC proceeding (*Re: Dynegy LNG Production Terminal, LP*, Docket No. CP01-423-000). September 2001

  Subject: Analysis of market power impacts of proposed LNG facility development.

Missouri Gas Energy Corp.

- FERC rate proceeding (*Re: Kansas Pipeline Corporation*, Docket No. RP99-485-000)

  Subject: Gas supply analysis to determine pipeline depreciation rates as part of an overall rate proceeding.

Green Mountain Power Corp.

- Vermont Public Service Board rate proceedings
  - *In the Matter of Green Mountain Power Corporation requesting a 12.93% Rate Increase to take effect January 22, 1999*, Docket No. 6107. Subject: Analysis of the appropriate discount rate, treatment of environmental costs, and the treatment of risk and uncertainty as part of a major power-purchase agreement with Hydro-Quebec.
  - *Investigation into the Department of Public Service's Proposed Energy Efficiency Utility*, Docket No. 5980. Subject: Analysis of distributed utility planning methodologies and environmental costs.

- *Tariff Filing of Green Mountain Power Corporation requesting a 16.7% Rate Increase to take effect 7/31/97*, Docket No. 5983. Subject: Analysis of distributed utility planning methodologies and avoided electricity costs.
- *Tariff Filing of Green Mountain Power Corporation requesting a 16.7% Rate Increase to take effect 7/31/97*, Docket No. 5983. Subject: Valuation of a long-term power purchase contract with Hydro-Quebec in the context of a determination of prudence and economic used-and-usefulness.

United Illuminating Company

- Connecticut Dept. of Public Utility Control proceeding (*Application of the United Illuminating Company for Recovery of Stranded Costs*, Docket No. 99-03-04)

  Subject: Development and application of dynamic programming models to estimate nuclear plant stranded costs.

COMMERCIAL LITIGATION EXPERIENCE

- *Idaho Power Co. v. Glenns Ferry Cogeneration Partners, L.P.*, U.S. District Court, District of Idaho, Case No. 1:11-cv-00565-CWD. Expert report on damages associated with breach of power sales contract.

- *Vacqueria Tres Monjitas and Suiza Dairy, Inc. v. Jose O. Laboy, in his Official capacity, as the Secretary of the Department of Agriculture for the Commonwealth of Puerto Rico, and Juan R. Pedro-Gordian, in his official capacity, as Administrator of the Office of the Milk Industry Regulatory Administration for the Commonwealth of Puerto Rico,* U.S. District Court, District of Puerto Rico, Civil Case No. 04-1840. Expert testimony and report on country risk and failure to provide adequate compensation to fresh milk processors in Puerto Rico.

- *Lorali, Ltd., et al. v. Sempra Energy Solutions, LLC, et al.* District Court of Texas, 92nd Judicial Court, Hidalgo County, Cause No. C-356-10-A. Expert reports regarding liquidated damages associated with breach of retail electric supply contracts.

  DPL, Inc. and its subsidiaries v. William W. Wilkins, Tax Commissioner of Ohio, Case No. 2004-A-1437. Expert report on economic impacts of generation investment and qualification of electric utility investments as "manufacturing" investments for purposes of state investment tax credits.

- *IMO Industries v. Transamerica.* Estimated the appropriate discount rate to use for estimating damages over time associated with a failure of the insurance companies to reimburse asbestos-related damage claims and the resulting losses to the firm's value.

- *John C. Lincoln Hospital v. Maricopa County.* Performed statistical analysis to determine the value of a class of unpaid hospital insurance claims.

- *Catamount/Brownell, LLC. v. Randy Rowland.* Prepared an expert report on the damages associated with breach of commercial lease.

- *Lyubner v. Sizzling Platters, Inc.*. Performed an econometric analysis of damage claims based on sales impacts associated with advertising.

- *Pietro v. Pietro*. Estimated pension benefits arising from a divorce case.

- *Nat'l. Association of Electric Manufacturers v. Sorrell.* U.S. District Court for the District of Vermont. Expert report and testimony on the costs of labeling fluorescent lamps and the impacts of labeling laws on the demand for electricity.

ARBITRATION CASES

***TransCanada Hydro Northeast, Inc. v. Town of Littleton, New Hampshire*, (CPR File No. G-09-24).**

Subject: dispute regarding valuation for property tax purposes of a hydroelectric facility located on the Connecticut River.

Served as neutral on a three-person arbitration panel.

***Belize Electricity Limited v. Belize Public Utilities Commission* (Claim No. 512 of 2008)**.

Subject: Proceeding before the Supreme Court of Belize alleging that the Final Decision by the Belize Public Utilities Commission setting electric rates and tariffs for the 2008-2009 period were unreasonable and non-compensatory.

Prepared independent report on behalf of the Belize Supreme Court for arbitration of the dispute.

SELECTED BUSINESS CONSULTING EXPERIENCE

- For Fortis-TCI, prepared report on the economic impacts of the electric industry in the Turks and Caicos.

- For the COMPETE coalition, prepared a report on the economic impacts of state subsidized electric generating plants.
- For a confidential client, provided analysis on rate of return and capital structure, as well as key business and financial risks, for renegotiation of a long-term power-purchase agreement.
- For the Manhattan Institute, prepared a comprehensive report on the economic impacts of shutdown of the Indian Point Nuclear Facility.
- For Energy Choice Now, prepared a report on the economic benefits of retail electric competition in Michigan.
- For the COMPETE Coalition, prepared a report on how electric competition creates economic growth.
- For an industry group, developed econometric models of the impacts of shale gas production on U.S. natural gas and electric prices.
- For an environmental advocacy group, critically evaluated the financial implications of operating restrictions for an off-shore wind generating facility stemming from requirements under the U.S. Endangered Species Act.
- For a major investor-owned utility in the US, prepared a new system of short-term peak and energy forecasting models.
- For a major wholesale electric generation company, prepared comprehensive economic impact studies for use in FERC hydroelectric relicensing proceedings.
- For a major investor-owned utility in the Southwest US, prepared a detailed econometric model and wrote a comprehensive report on residential price elasticity that was required by regulators.
- For a major investor-owned utility in the Southwest US, developed a methodology to value nuclear plant leases that incorporated future uncertainty regarding greenhouse gas regulations.
- Faculty member, PURC/World Bank International Training Program on Utility Regulation and Strategy, University of Florida, Public Utility Research Center, Gainesville, FL, 2008 – 2009. Courses taught:
    - Sector Issues: Basic Techniques–Energy
    - Sector Issues in Rate Design: Energy
    - Sector Issues in Rate Design: Energy–Case Studies
    - Transmission Pricing Issues
- For a major solar energy firm, evaluated costs and benefits of alternative solar technologies; assisted with siting and transmission access issues.

- For the South African Department of Minerals and Energy, recommended pricing methods and regulatory accounts to ensure that petroleum product prices appropriately reflected costs and to enhance the incentives for industry investment "Final Report for Task 141. "
- For industrial customers in the State of Vermont, prepared a position paper on the impacts of demand side management funding on electric rates and competitiveness.
- For a major New York brokerage firm, performed a fairness opinion valuation of a gas-fired electric generating facility.
- For electric utilities undergoing restructuring, developed comprehensive economic models to value buyer offers associated with nuclear power plant divestitures.
- For a large municipal electric utility in Florida, analyzed real option values of alternative proposed purchased generation contracts whose strike prices were tied to future natural gas and oil prices, and developed contract recommendations.
- For a municipal electric utility in Florida, developed an analytical model to determine risk-return tradeoffs of alternative generation portfolios, identify an efficient frontier of generation asset portfolios, and recommended asset purchase and sale strategies.
- For Central Vermont Public Service Corp. and Green Mountain Power Corp., developed analyses of distribution capacity investments accounting for uncertainty over future peak load growth.
- For a major electric utility in Latin America, developed risk management strategies for hedging natural gas supplies with minimal up-front investment; prepared training materials for utility staff; and wrote the utility's risk management Policies and Procedures Manual.
- For a major nuclear plant owner and operator in the U.S., prepared reports of the economic benefits of nuclear plant operation and development.
- For the Electric Power Supply Association, prepared numerous policy papers addressing wholesale electric market design and competition.
- For the California Energy Commission, developed a new policy approach to renewables feed-in tariffs and developed portfolio analysis models to develop an "efficient frontier" of generation portfolios for the state.
- For a major nuclear plant owner and operator, assessed the likelihood of relicensing a specific nuclear plant in New England, given state regulatory concerns over on-site spent fuel storage.

- For a large investor-owned utility in the Southeast, analyzed alternative environmental compliance strategies that directly incorporated uncertainty over future emissions costs, environmental regulations, and alternative pollution control technology effectiveness.
- For a Special Legislative Committee of the Province of New Brunswick, served as an expert advisor on the development of a deregulated electric power market.
- For the Bonneville Power Administration, developed models to assess the economic impacts of local generation resource development in Washington State and Oregon.
- For an electric utility in the Pacific Northwest, assisted in negotiations surrounding relicensing of a large hydroelectric generating facility.
- Served as an expert advisor for the Northwest Power Planning Council regarding future power supplies, load growth, and economic growth.

PROFESSIONAL ACTIVITIES

- Reviewer, *Energy*
- Reviewer, *The Energy Journal*
- Reviewer, *Energy Policy*
- Reviewer, *Journal of Regulatory Economics*
- Editorial Board Member, *Natural Gas & Electricity*

PROFESSIONAL ASSOCIATIONS

- Energy Bar Association
- Society for Benefit-Cost Analysis

PUBLICATIONS

Peer-reviewed journal articles

- Lesser, J., "The High Cost of Low-Value Wind Power," *Regulation*, Spring 2013, pp. 22-27.
- Lesser, J., "Wind Generation Patterns and the Economics of Wind Subsidies," *The Electricity Journal* 26, Jan/Feb. 2013, pp. 8-16.
- Lesser, J., "Gresham's Law of Green Energy," *Regulation*, Winter 2010-2011, pp. 12-18.

- Lesser, J., and E. Nicholson, "Abandon all Hope? FERC's Evolving Standards for Identifying Comparable Firms and Estimating the Rate of Return," *Energy Law Journal* 30 (April 2009): 105-132.
- Lesser, J. and X. Su. "Design of an Economically Efficient Feed-in Tariff Structure for Renewable Energy Development." *Energy Policy* 36 (March 2008) 981–990.
- Lesser, J. "The Economic Used-and-Useful Test: Its Origins and Implications for a Restructured Electric Industry." *Energy Law Journal* 23 (November 2002): 349–82.
- Lesser, J., and C. Feinstein. "Electric Utility Restructuring, Regulation of Distribution Utilities, and the Fallacy of 'Avoided Cost' Rules." *Journal of Regulatory Economics* 15 (January 1999): 93–110.
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- Lesser, J. and C. Strother, "Natural Gas Storage," in *Energy Law and Transactions*, Lexis/Nexis, 2012 ed.
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- Lesser, J., "Rethinking Green Energy Mandates," *Natural Gas and Electricity* (August 2013): 23-25.
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- Lesser, J., "Nuclear Fallout," *Natural Gas & Electricity* (May 2011):31-33.
- Lesser, J., "Texas Two-Step: EPA's Greenhouse Gas Permitting Takeover," *Natural Gas & Electricity* (March 2011):21-23.
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- Lesser, J., "Let the Tough Choices Begin: Affordable or Green?," *Natural Gas & Electricity* (June 2010): 27-29.
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- Lesser, J. and N. Puga, "Public Policy and Private Interests: Why Transmission Planning and Cost-Allocation Methods Continue to Stifle Renewable Energy Policy Goals," *The Electricity Journal* (December 2009): 7-19.

- Lesser, J, "Short Circuit: Will Electric Cars Provide Energy and Environmental Salvation?" *Natural Gas & Electricity* (November 2009): 27-28.
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- Lesser, J., "Blowin' in the Wind: Renewable Energy Mandates, Electric Rates, and Environmental Quality." *Natural Gas & Electricity* (October 2007): 26-28.
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- Lesser, J., "Goldilocks and the Three Climates." *Natural Gas & Electricity* (April 2007): 22–24.
- Lesser, J., "Command-and-Control Still Lurks in Every Legislature." *Natural Gas & Electricity* (February 2007): 8–12.
- Lesser, J., "Overblown Promises: The Hidden Costs of Symbolic Environmentalism." *Livin' Vermont* (January/February 2005): 7, 27.
- Lesser, J., and G. Israilevich, "The Capacity Market Enigma." *Public Utilities Fortnightly* 143 (December 2005): 38-42.
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- Lesser, J., and S. Chapel, "Keys to Transmission and Distribution Reliability." *Public Utilities Fortnightly* 142 (April 2004): 58–62.
- Lesser, J. ,"DCF Utility Valuation: Still the Gold Standard?" *Public Utilities Fortnightly* 141 (February 15, 2003): 14–21.
- Lesser, J., "Welcome to the New Era of Resource Planning: Why Restructuring May Lead to More Complex Regulation, Not Less." *The Electricity Journal* 15 (July 2002): 20–28.
- Lesser, J., and C. Feinstein, "Identifying Applications for Distributed Generation: Hype vs. Hope." *Public Utilities Fortnightly* 140 (June 1, 2002): 20–28.
- Lesser, J., et al., "Utility Resource Planning: The Need for a New Approach." *Public Utilities Fortnightly* 140 (January 15, 2002): 24–27.
- Lesser, J., "Distribution Utilities: Forgotten Orphans of Electric Restructuring?" *Public Utilities Fortnightly* 137 (March 1, 1999): 50–55.

- Lesser, J., "Regulating Distribution Utilities in a Restructured World." *The Electricity Journal* 12 (January/February 1999): 40–48.
- Lesser, J., "Is it How Much or Who Pays? A Response to Rothkopf." *The Electricity Journal* 10 (December 1997): 17–22.
- Lesser, J., and M. Ainspan, "Using Markets to Value Stranded Costs." *The Electricity Journal* (October 1996): 66–74.
- Lesser, J., "Economic Analysis of Distributed Resources: An Introduction." *Proceedings*, First Annual Conference on Distributed Resources, Electric Power Research Institute, Kansas City, MO, July 1995.
- Lesser, J., "Distributed Resources as a Competitive Opportunity: The Small Utility Perspective." *Proceedings*, First Annual Conference on Distributed Resources, Electric Power Research Institute, Kansas City, MO, July 1995.
- Lesser, J., and M. Ainspan, "Retail Wheeling: Deja vu All Over Again?" *The Electricity Journal* 7 (April 1994): 33–49.
- Lesser, J., "An Economically Rational Approach to Least-Cost Planning: Comment." *The Electricity Journal* 4 (October 1991).
- Lesser, J., "Long-Term Utility Planning Under Uncertainty: A New Approach." Paper presented for the Electric Power Research Institute: *Innovations in Pricing and Planning*, May 1990.
- Lesser, J., "Centralized vs. Decentralized Resource Acquisition: Implications for Bidding Strategies." *Public Utilities Fortnightly* (June 1990).
- Lesser, J., "Most Value—The Right Measure for the Wrong Market?" *The Electricity Journal* 2 (December 1989): 47–51.

Other Publications

- Lesser, J., "Wind power creates market havoc, is unreliable and costly," *Columbus* (Ohio) *Dispatch*, November 22, 2012.
- Lesser, J., and R. Bryce, "The High Cost of Closing Indian Point," *New York Post*, August 8, 2012.
- Lesser, J., "Cap-and-Trade for Gasoline?" *Wall Street Journal*, June 14, 2008, A14.

Selected speaking engagements

- "The Need for a Texas Capacity Market," Presentation to the Gulf Coast Power Association, April 9, 2013.
- "The Regulatory Compact and Pipeline Competition," presentation to the Energy Bar Association, Western Chapter, Annual Meeting, San Francisco, CA, February 22, 2013.
- "Public Policy and Energy Markets: Good Intentions Gone Astray," presentation to the Independent Power Producers of New York, Fall Conference, September 13, 2012.
- "EPA Regulation of Generator Emissions – Key Market Issues," Energy Bar Association, Annual Meeting, April 28, 2012.
- "Competitive Energy Markets: How are they Working?" Constellation Executive Energy Forum, November 2, 2011.
- "The Failures of Transmission Planning and Policy," Harvard Electric Policy Group, February 25, 2010.
- "Financing the Smart Grid," Energy Bar Association Seminar, Washington, DC, December 4, 2009.
- "Renewable Power: At the Crossroads of Economics and Policy," Presentation to the Utilities State Government Organization, Newport, Rhode Island, July 13, 2009.
- "The Stimulus Act and Laws they Didn't Teach You in Law School," presentation to the 27th National Regulatory Conference, Williamsburg, VA, May 19, 2009.
- "Rate Recovery for Capital Intensive Generation: Rate Base and Construction Work in Progress," Law Seminars International, Las Vegas, NV, February 5, 2009.
- "Financial Risks Faced by Regulated Utilities: Implications for the Cost of Capital and Ratemaking Policies," Law Seminars International, Las Vegas, NV, February 7, 2008.
- "Alternative Regulatory Structures and Tariff Mechanisms: Practical approaches to providing low-cost, environmentally responsible energy and how to avoid some dangerous pitfalls." Western Energy Institute, October 1, 2007.
- "Economics and Energy Regulation." Law Seminars International, Washington, DC, March 15-16, 2007.
- "Energy in the Northeast: Resource Adequacy & Reliability." Law Seminars International, Boston, MA, October 16–17, 2006.
- "Energy in the Southwest: New Directions in Energy Markets and Regulations." Law Seminars International, Santa Fe, NM, July 14, 2006.

- "Energy and the Environment." Vermont Journal of Environmental Law, South Royalton, VT, March 10, 2006.
- "Electricity and Natural Gas Regulation: An Introduction." Law Seminars International, Washington, DC, March 17–18, 2005.

EXHIBIT JAL/CDF-2

Charles D. Feinstein Curriculum Vitae

CHARLES D. FEINSTEIN, Ph.D.

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Redwood City, CA 94062
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(408) 554-4102 (office)
(650) 450-1968 (cell)

VMN Group LLC, Co-founder and Chief Executive Officer

and

Associate Professor, Department of Operations Management and Information Systems (OMIS), The Leavey School of Business, Santa Clara University, Santa Clara, CA.

EXPERTISE:

Application of mathematical techniques to create state-of-the-art models and decision support software. Specialist in mathematical modeling, operations research, risk analysis, optimization, systems analysis, and applied economics. Current interests address problems of investment, risk, reliability and design with particular attention to electric power systems. Problems addressed include strategies for managing aging assets (with respect to replacement, repair, and testing), methods for prioritizing projects, and strategies for integration of distributed generation into existing systems.

SELECTED PAST PROJECTS & VMN GROUP LLC CLIENTS

- **Internal Revenue Service**: Policy analysis and resource allocation, including capital investments, for IRS information processing systems
- **PJM Interconnect**: Optimal control of transmission system assets (including valuation and siting of spare transformers).
- **Southern Company, Alliant Energy, MidAmerican Energy, United Illuminating, ConEd, ComEd, PECO:** Optimal control of aging distribution and transmission system assets – underground cable, poles, breakers, transformers.
- **Southern Company, HECO, Nashville Electric System, ComEd, PECO, Exelon, BGE:** Project prioritization for distribution utilities.
- **Green Mountain Power (VT):** Electrical supply contract risk analysis.
- **PG&E, EPRI, NREL:** Distributed generation valuation and siting.
- **Failure Analysis, Inc.:** USN helicopter gearbox failure prediction.
- **Santa Clara County (CA) Transit District:** Information system requirements and design.
- **EPRI**: Nuclear reactor leadtimes risk analysis; forecasting customer needs for electric power system reliability.
- **Lockheed MSD**: Risk analysis and control for contract management
- **Xerox Corp.**: Computer laser printer demand forecast model; customer value attribute importance ranking methodology
- **State Welfare Dept (MD, CT)**: Systems analysis and design for interstate AFDC processing.
- **SRI International**: Air traffic control failure analysis.

PROFESSIONAL EXPERIENCE

VMN Group LLC, Redwood City, CA — Chief Executive Officer

Principal of consulting firm. The firm provides state-of-the-art software implementations of mathematical models for decision support. Current applications include electric distribution system planning, capital budgeting, reliability analysis, customer needs specification. The firm has specific expertise in optimization, decision analysis, expert judgment, stochastic control. (April 2001 - present)

Independent Consultant

Created consulting practice applying optimization methods and economic analysis. Projects included analysis of distributed resources for electric distribution systems, creation of mathematical models to support capital budgeting decisions, reliability analysis, asset management, system load forecasts, applied statistical analysis, expert testimony in rate cases. (September 1982 - April 2001)

Applied Decision Analysis, Inc., Menlo Park, CA — Senior Decision Analyst

Senior staff of management consulting firm. Projects included construction of mathematical model to explain and forecast nuclear reactor costs and leadtimes; development of forecasting model for office information systems; economic analysis of alternate sources of electric power; market analysis of personal computers. (April 1981 -September 1982)

Xerox Corporation, PARC, Palo Alto, CA — Research Engineer

Responsible for construction of forecasting model for Xerox printing systems. Input to model was extensive market research data describing needs and preferences of randomly sampled customers. Model output included optimal printing system configuration by site, probability of choice of alternative configurations by site, effect of competitive scenarios, and ten-year forecast of placements and revenues. (November 1979 -April 1981)

Member of Analysis Research Group, PARC. Development of techniques for information analysis of office systems. Main result: theory of information trees, a mathematical model that is able to describe and optimally configure information systems. The advancement of the theory and associated modeling techniques is still an active area of research. (June 1976 - November 1979)

SRI, Inc. Menlo Park, CA — Research Engineer

Member of Transportation Engineering and Control Group. Application of mathematical modeling and probabilistic analysis techniques to problem of air traffic safety. (June 1975 - June 1976)

IBM, Inc. New York, NY — Salesman

Staff of New York Banking Office. Assisted in formulating and marketing proposals for computer systems and participated in many sales training classes. (August 1973 -July 1974)

Other Professional Employment

New York City School System, New York, NY — Teacher

Rikers Island, Bronx, NY (Correctional Institution). Subjects: mathematics, English, history, science. (September 1971 - June 1973)

RCA, Inc. Van Nuys, CA — Engineer

Designed shipboard heat transfer systems. (Summer 1968)

Boeing, Inc. Kent, WA — Engineer

Aerodynamic design and testing. (Summer 1967)

ACADEMIC EXPERIENCE:

1982–present. Santa Clara University.

Research interests: Electric power systems analysis and investment planning; design and analysis of information systems; mathematical modeling; theory of optimal control; mathematical programming theory and algorithm development; forecasting techniques; dynamic systems analysis and control. Courses: statistics, operations management, systems analysis, seminar in mathematical modeling, operations research.

1985--2001. University of California, Berkeley.

Visiting Associate Professor, Department of Industrial Engineering and Operations Research. Courses: Introduction to operations research, operations research methods, linear programming, production systems analysis and management, engineering economics.

1994--2012. Stanford University.

Consulting Associate Professor, Department of Management Science and Engineering (formerly Department of Engineering-Economic Systems). Course: investment science.

1993 (Summer). Stanford University.

Visiting Associate Professor, Department of Engineering-Economic Systems, School of Engineering. Course: investment science.

1980--88. Stanford University.

Consulting Associate Professor, Department of Engineering-Economic Systems, School of Engineering. Courses: dynamic systems, optimal dynamic systems (optimal control).

1975--80. Stanford University.

Acting Instructor & Teaching Assistant, Department of Engineering-Economic Systems. Course: dynamic systems.

INTERNATIONAL ACADEMIC EXPERIENCE

Summer, 1992 American University of Armenia, Yerevan, Armenia.

Invited to teach in inaugural session of the engineering program. Courses taught: production systems analysis, engineering economics.

EDUCATION

PhD, 1980, Stanford University, Engineering-Economic Systems
MS, 1978, Stanford University, Mathematics
MS, 1968, Stanford University, Aeronautics and Astronautics
BS, 1967, Cooper Union, Mechanical Engineering

SELECTED PUBLICATIONS

"Opening the Black Box: A New Approach to Utility Asset Management." *Public Utilities Fortnightly*. January, 2014, 37-42.

"A Non-linear Programming Approach to Maintenance Budgeting for Multi-component Systems" (with R. S. Ferreira, L.A. Barroso, C.L.T. Borges). *Proc. IEEE PES GM,* July, 2013, Vancouver, BC, Canada.

"The Role of Uncertainty in Managing Aging Assets In Electric Utility Systems" (with P.A. Morris). *IEEE PES Transmission and Distribution.* New Orleans, April 2010. (pdf version of this paper is available upon request.)

"Spare Transformers and More Frequent Replacement Increase Reliability, Decrease Cost" (with P.A. Morris), *Natural Gas and Electricity, Wiley Periodicals,* November 2008, 18-27.

"Substation Asset Health Measurement Method (with P.A. Morris), EPRI, Palo Alto, CA: December 2007. 1013820.

"Distribution Asset Health Measurement Method (with P.A. Morris), EPRI, Palo Alto, CA: December 2007. 1013817.

"Optimal Replacement of Underground Distribution Cables" (with J.Bloom and P.A. Morris). *IEEE Power Systems Conference and Exposition*. Tampa, FL. 2006. (pdf version of this paper is available upon request.)

"Substation Transformer Asset Management and Testing Methodology (with P.A. Morris and J. Bloom) EPRI, Palo Alto, CA: December 2006. 1012505.

"Guidelines for Intelligent Asset Replacement, Wood Poles. Volume 4" (with P.A. Morris and J. Bloom). EPRI, Palo Alto, CA: December 2006. 1012500

"Equipment Failure Modeling for Underground Distribution Cables (with P.A. Morris and J. Bloom). EPRI, Palo Alto, CA: December 2006, 1012498

"Guidelines for Intelligent Asset Replacement, Underground Distribution Cables. Volume 3" (with P.A. Morris and J. Bloom). EPRI, Palo Alto, CA: December 2005. 1010740.

"Guidelines for Intelligent Asset Replacement, Volume 2" (with P.A. Morris and J. Bloom). EPRI, Palo Alto, CA: December 2004. 1002087.

"Asset Population Model with Testing for Managing Aging Power Delivery Assets" (with P.A. Morris). EPRI, Palo Alto, CA: November 2004. 1008562.

"Guidelines for Intelligent Asset Replacement, Volume 1" (with P.A. Morris and J. Bloom). EPRI, Palo Alto, CA: December 2003. 1002086.

"Cable Reliability Management Strategies: Research Status Report" (with P.A. Morris). EPRI, Palo Alto, CA: December 2003.

"Medium Voltage Cable Failure Trends: Research Status Report" (with P.A. Morris). EPRI, Palo Alto, CA: December 2003.

"Estimating Reliability of Critical Distribution System Components" (with G.L. Hamm and P.A. Morris). EPRI, Palo Alto, CA: December 2003. 1001704.

"Distributed Generation: Hype vs. Hope" (with J.A. Lesser). *Public Utilities Fortnightly*, June 1, 2002, 23-30.

"Distribution System Reliability Modeling: Research Status Report" (with P.A. Morris). EPRI, Palo Alto, CA: December 2001. 1001882.

"Technical Review of DS-RADS Model" (with S.W.Chapel and P.A. Morris). EPRI, Palo Alto, CA: December 2001. 1001881.

"A Review of the Reliability of Electric Distribution System Components: EPRI White Paper" (with P.A. Morris and G.L. Hamm). EPRI, Palo Alto, CA: December 2001. 1001873.

"Customer Needs for Electric Power Reliability and Power Quality: EPRI White Paper" (with P.A. Morris and C.Downs). EPRI Technical Report 1000428, October 2000.

"Reliability of Electric Utility Distribution Systems: EPRI White Paper" (with P.A. Morris and R. Cedolin). EPRI Technical Report 1000424, October 2000.

"The Strategic Role of Distributed Resources in Distribution Systems" (with Stephen W. Chapel). *Energy 2000 (Proc. 8th Int'l Energy Forum)*. July, 2000. 787-792.

"The Strategic Role of Distributed Resources in Distribution Systems." EPRI Report TR-114095. November 1999.

"Electric Utility Restructuring, Regulation of Distribution Utilities, and the Fallacy of "Avoided Cost" Rules" (with Jonathan A. Lesser). *Journal of Regulatory Economics.* 1999. 15:93-110.

"Defining Distributed Resource Planning" (with Jonathan A. Lesser). *Energy Journal. Special Issue on Distributed Resources*. Jan.1998, 40-62.

"Capacity Planning Under Uncertainty: Developing Local Area Strategies for Integrating Distributed Resources" (with Peter A. Morris and Stephen W. Chapel). *Energy Journal. Special Issue on Distributed Resources*. Jan.1998, 85-110.

"The Distributed Utility: A New Electric Utility Planning and Pricing Paradigm" (with Ren Orans and Stephen W. Chapel). *Annual Review of Energy and the Environment.* 1997. 22:155-85.

"A Reformulation of a Mean-Absolute Deviation Portfolio Optimization Model" (with Mukund N. Thapa). *Management Science*, Vol.39, No.12, December 1993, 1552-1553.

"Evaluation of Utility Grid-Connected Battery Plants Using Area and Time Specific Marginal Costs" (with S.W. Chapel and R. Orans). Fourth International Conference, Batteries for Energy Storage, Berlin. Vol.II, 140-171, October, 1993.

"An Introduction to the Distributed Utility Valuation Project Monograph." EPRI TR-102461, PG&E 005-93.13, July 1993.

"Distributed Utility Valuation Project Monograph" (with R.Orans, R. Pupp, et.al.). Final Report. EPRI TR-102807, PG&E 005-93.12, July, 1993.

"Screening Strategies to Inhibit the Spread of AIDS" (with Steven Nahmias). *Socio-Economic Planning Sciences*, Vol.24, No. 4, 1990, 249-260.

"Deciding Whether to Test Student Athletes for Drug Use." *Interfaces*, Vol. 20, No. 3, May-June 1990, 80-87.

"Mathematical Model for Predicting Helicopter Gearbox Failure Modes" (with J.D. Roughgarden and W. E. Littman). Final Report. SBIR N00421-88-C-0336. September, 1989.

"Information Trees: A Model of Information Flow in Complex Organizations" (with P.A. Morris). *IEEE Transactions on Systems, Man, and Cybernetics*, Vol. 18, No. 3, 1988, 390-401.

"Analysis of a Drug-Testing Program for Intercollegiate Athletes." *Journal of Policy Analysis and Management*, Vol. 7, No. 3, 1988, 548-550.

"Statistical Analysis of Nuclear Plant Lead Times" (with D. S. Bauman). *Energy Systems and Policy*. Vol. 10, No. 3, 1987, 237-255.

"Analysis of the Maryland Interstate Case Processing System" (with P. Morris and D. Murphy). Final Report. Maryland Interstate Grant No. 19/E/1005/3/01. July, 1986.

"An Analysis of Personal Computing Needs and Resources for the Santa Clara County Department of Transportation" (with S. Nahmias and S. Smith). Final Report. February, 1986.

"A 'Funnel' Turnpike Theorem for Optimal Growth Problems with Discounting" (with S.S. Oren). *Journal of Economic Dynamics and Control*, 9 (1985), 25-39.

"A Newton-type Algorithm for the Solution of the Implicit Programming Problem" (with S.S. Oren). *Mathematics of Operations Research*, Vol. 9, No. 1, February 1984, 75-86.

"An Analysis of Power Plant Construction Leadtimes" (with D.S. Bauman and M.A. Radlauer). Final Report, EPRI Project 1785-3, EPRI EA-2880, Volume 2, February, 1984.

"Local Stability Properties of the Modified Hamiltonian Dynamic System" (with S.S. Oren). *Journal of Economic Dynamics and Control*, 6 (1983), 387-397.

"Analysis of the Asymptotic Behavior of Optimal Control Trajectories: The Implicit Programming Problem" (with D.G. Luenberger). *SIAM Journal on Control and Optimization*, Vol. 19, No. 5, September 1981, 561-585.

"The LeChatelier Principle", Department of Engineering-Economic Systems, Internal Memo #1-77, September, 1977.

"An Information Analysis Study of the Stanford Engineering Library" (with P.A. Morris), Xerox PARC, ARG Technical Report #77-1, June 1977.

"Evaluating Alternative Library Organizations with Decision Trees" (with S.A. Smith and P.A. Morris), Xerox PARC, ARG Technical Report #77-5, June, 1977.

Doctoral Dissertation: Implicit Programming: A Method for Characterizing the Asymptotic Behavior of Optimal Control Trajectories, Stanford University, April, 1980.

EXHIBIT JAL/CDF-3

GTS-RateCase2015_DR_IP_02 -Q008

PACIFIC GAS AND ELECTRIC COMPANY
GTS RATE CASE 2015
Application 13-12-012
Data Response

PG&E Data Request No.:	IndicatedProducers_002-008		
PG&E File Name:	GTS-RateCase2015_DR_IndicatedProducers_002-Q008		
Request Date:	March 14, 2014	Requester DR No.:	002
Date Sent:	April 3, 2014	Requesting Party:	Indicated Producers
PG&E Witness:	Nickolas Stavropoulos	Requester:	Evelyn Kahl/ John McIntyre/ Kenneth Sosnick

CHAPTER 1 – INTRODUCTION AND POLICY

QUESTION 8

On Page 1-8, Line 6, PG&E mentions that Gas Operations developed a strategic plan to pursue PAS 55 certification.

a. Does PG&E consider PAS 55 the best plan/methodology to use to safely manage the integrity of its pipeline system? i. If no, what plan/methodology does PG&E consider the best to safely manage the integrity of its pipeline system? Please provide in electronic format any documents, models, methodologies, or any other related source that make up what PG&E considers the best plan/methodology.

b. Please provide in electronic format a copy of the strategic plan.

ANSWER 8

a. Publicly Available Specification (PAS) 55 is not a plan or methodology to use to safely manage the integrity of a pipeline system. Rather, it is a rigorous globally recognized certification that represents the highest standards for asset management planning and is currently used by over 50 public and private asset-intensive organizations in 10 countries and 15 industry sectors including Bonneville Power Authority, Vattenfall (a multi-national European utility), London Underground, Gas Unie (a natural gas transmission company in the Netherlands), and Gatwick Airport. This certification requires an asset owner to holistically and systemically manage all aspects of the life cycle of assets in a risk-based manner.

PAS 55 is not the methodology used by PG&E for pipeline integrity management. ASME standard B31.8S is the standard PG&E uses in managing the integrity of pipeline assets under the umbrella of the PAS 55 framework. See testimony on page 2-14 that references to the application of ASME B31.8S.

The testimony does not state that Gas Operations developed a strategic plan to pursue PAS 55 certification. It states, “The standard requires that Gas Operations develop a strategic plan and then systematically execute it.” PG&E prepares a five-year view of its strategic plan annually to guide its asset management process and efforts. See Integrated Planning Process Gas Operations, Session 1, in attachment GTS-RateCase2015_DR_TURN_001-Q01Atch26, which is the Gas Operations strategic plan for 2013. PG&E prepares its execution plan annually. See GTS-RateCase2015_DR_TURN_001-Q01Atch27. Finally, the Asset Management Strategy and Objectives describes the asset management strategy for PG&E’s gas system physical assets and shows the link between the other key documents and processes in the wider asset management system. See GTS-RateCase2015_DR_ORA_007-Q04Atch01 for the July 2013 Asset Management Strategy and Objectives.

b. Please see part (a) above.

EXHIBIT JAL/CDF-4

GTS-RateCase2015_DR_IS_06-Q003

PACIFIC GAS AND ELECTRIC COMPANY
Gas Transmission and Storage Rate Case 2015
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Data Response

PG&E Data Request No.:	IndicatedShippers_006-03		
PG&E File Name:	GTS-RateCase2015_DR_IndicatedShippers_006-Q03		
Request Date:	July 3, 2014	Requester DR No.:	No. 6
Date Sent:	July 21, 2014	Requesting Party:	Indicated Shippers
PG&E Witness:	Bennie Barnes	Requester:	Evelyn Kahl

QUESTION 3

For the 2012 Version of ASME B31.8S, there is a table at Page 14, Section 5.6.1-1that lays out a time table to do integrity assessment for pipeline assets.

(a) Did PG&E follow the interval years and timeline to do the necessary work as described in this Table 5.6.1-1?

(b) Please explain in detail how PG&E followed the process for each step in Table 5.6.1-1 or how PG&E has deviated away from following the process for each step. Identify any steps that were skipped and what PG&E did in lieu of completing such steps.

(c) Is PG&E's Direct Assessment program, both historical and forecast, in line with Table 5.6.1-1? Please explain this answer in detail.

(d) How does PG&E determine when to employ Direct Assessment and when to use other means of asset evaluation?

(e) Please include all work completed for PG&E's direct assessment from 2004 to 2014

  (i) Please describe how the work for direct assessment from 2004 to 2014 followed or deviated from the process in Table 5.6.1-1. Please identify any steps PG&E skipped and what PG&E did in lieu of completing those steps.

ANSWER 3

PG&E notes that 49 Code of Federal Regulations (CFR) Part 192 does not recognize the use of the 2012 Version of American Society of Mechanical Engineers (ASME) B31.8S; 49 CFR Part 192 references the 2004 version of ASME B31.8S.

(a) No, because the 2012 version of ASME B31.8S is not the version authorized by 49 CFR Part 192. However, PG&E used a similar table, Table 3, in the 2004 version. PG&E also uses 49 CFR 192.939 to set maximum re-assessment intervals.

(b) PG&E's process for determining reassessment intervals is described in its risk management procedure, RMP-06, section 11.1, "Assessment Intervals" on pages 29 through 30. For RMP-06, see attachment GTS-RateCase2015_DR_IndicatedProducers_002-Q085Atch03CONF to PG&E's

response to IndicatedProducers_002-Q085. Maximum reassessment intervals are established using ASME B31.8S, Table 3. For External Corrosion Direct Assessment (ECDA), PG&E further adds a maximum 5 year interval for pipelines operating at or above 50% Specified Minimum Yield Strength (SMYS) based on the guidance by National Association of Corrosion Engineers (NACE) SP0502-2008. PG&E further notes that maximum reassessment intervals are not allowed to exceed the requirements of 49 CFR 192.939. Shorter reassessment intervals are governed by the processes described in PG&E's risk management procedure, RMP-17, "Long Term Integrity Management Plan", section 6.3. The main purpose of this portion of RMP-17 is to confirm the maximum reassessment interval established by RMP-06. RMP-17 is provided as attachment "GTS-RateCase2015_DR_ORA_074-Q08Atch01CONF".

(c) PG&E's Direct Assessment program is in line with Table 3, in the 2004 version of ASME B31.8S, as required by 49 CFR Part 192 regulation.

(d) PG&E uses RMP-06, "APPENDIX C. ASSESSMENT METHOD SELECTION".

(e) For the pipe assessed using Direct Assessment, please see the response GTS-RateCase2015_DR_TURN_011-Q02 and GTS-RateCase2015_DR_ORA_074-Q01. For pipe assessed using Direct Assessment in 2013, also see GTS-RateCase2015_DR_ORA_070-Q01. For workscope, see GTS-RateCase2015_DR_ORA_070-Q08. For a discussion or re-assessment miles, please see GTS-RateCase2015_DR_ORA_070-Q04

(i). See response above.

EXHIBIT JAL/CDF-5

GTS-RateCase2015_DR_IS_10-Q003

GTS-RateCase2015_DR_IS_10-Q005

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Data Response

PG&E Data Request No.:	IndicatedShippers_010-03		
PG&E File Name:	GTS-RateCase2015_DR_IndicatedShippers_010-Q03		
Request Date:	July 18, 2014	Requester DR No.:	010
Date Sent:	July 28, 2014	Requesting Party:	Indicated Shippers
PG&E Witness:	Bennie Barnes	Requester:	Evelyn Kahl/John McIntyre

QUESTION 3

For external corrosion direct assessment, please provide a detailed breakdown of historic costs from 2004 to 2014 for:

(a) Pre-assessment;

(b) Above ground surveys;

(c) Direct examination and NDE; and

(d) Post-assessment of previous year projects.

Please identify the specific work completed and the costs associated with the work completed. Please see WP 4A-17 for a reference of what specific and detailed information the Indicated Shippers are seeking.

ANSWER 3

For historical costs associated with the External Corrosion Direct Assessment (ECDA) program, please see the response to GTS-RateCase2015_DR_ORA_083-Q10. Please note that costs for years prior to 2009 are not readily available, and as such, were not provided.

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PG&E Data Request No.:	IndicatedShippers_010-05		
PG&E File Name:	GTS-RateCase2015_DR_IndicatedShippers_010-Q05		
Request Date:	July 18, 2014	Requester DR No.:	010
Date Sent:	July 28, 2014	Requesting Party:	Indicated Shippers
PG&E Witness:	Bennie Barnes	Requester:	Evelyn Kahl/John McIntyre

QUESTION 5

For internal corrosion direct assessment, please provide a detailed breakdown of historic costs from 2004 to 2014 for:

(a) Pre-assessment;

(b) Above ground surveys;

(c) Direct examination and NDE; and

(d) Post-assessment of previous year projects.

Please identify the specific work completed and the costs associated with the work completed for the above-mentioned items.

ANSWER 5

Historical costs prior to 2009 are not readily available, and as such, PG&E is only providing costs from 2009 to 2014. In addition, costs for the Internal Corrosion Direct Assessment (ICDA) program have not been historically tracked by phase of assessment, and as such, PG&E is only providing total annual program costs by year.

For the historical costs of the ICDA program by year from 2009 through 2014, please see the table below. Please note that the 2014 costs are through June 2014.

ICDA Expenditures (2009 - 2014)					
2009	2010	2011	2012	2013	2014
$ 45,511	$ 124,849	$ 377,097	$ 6,201,539	$ 10,775,500	$ 629,729

For the annual work scope for 2009 through 2013, please see the response to GTS-RateCase2015_DR_ORA_070-Q08. In addition, PG&E forecasts completing approximately 10.53 miles of ICDA in 2014.

EXHIBIT JAL/CDF-6

GTS-RateCase2015_DR_IS_09-Q007

PACIFIC GAS AND ELECTRIC COMPANY
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Data Response

PG&E Data Request No.:	IndicatedShippers_009-07		
PG&E File Name:	GTS-RateCase2015_DR_IndicatedShippers_009-Q07		
Request Date:	July 14, 2014	Requester DR No.:	009
Date Sent:	July 28, 2014	Requesting Party:	Indicated Shippers
PG&E Witness:		Requester:	Evelyn Kahl

QUESTION 7

In PG&E Testimony Page 2-14 Lines 2 to 7, PG&E states that "The Asset Management Plan for each asset family describes: the physical characteristics and location of the assets, asset health indices reflecting the condition, the risk assessment process, the overall quality, maturity, comprehensiveness and quality of data used to assess the threats and risks, and a vision for the desired state of the assets." Additionally, Page 2-14 Lines 9 to 14 state that "The Asset Management Plans also include Key Performance Indicators, which are metrics intended to measure progress and improvement in asset performance and the effectiveness of mitigation programs."

However, in PG&E's response to Indicated Shippers' Question 02-99(f), PG&E admitted that "PG&E plans to implement the asset health thresholds once they are developed. They will be defined in the Asset Management Plans." Furthermore, in the response to Question 02-99(a), PG&E also admitted that Key Performance Indicators "will be developed to trend and evaluate asset health scores to assist in identifying and prioritizing work and to evaluate the success of the program."

(a) Has PG&E implemented any asset health thresholds for any of the programs included over all asset families?

  (i) If yes, please identify and explain in detail what the asset health threshold is for each program for which PG&E has implemented an asset health threshold. Please provide in electronic format all documents and workpapers describing or illustrating how PG&E determined the asset health threshold for each program.

  (ii) Please identify and verify each and every program under all asset families of which PG&E has not developed an asset health threshold.

(b) Has PG&E developed any Key Performance Indicators for any of the programs included over all asset families?

  (i) If yes, please identify and explain in detail what the Key Performance Indicator is for each program for which PG&E has developed a Key Performance Indicator. Please provide in electronic format all documents and workpapers describing or illustrating how PG&E determined the Key Performance Indicator for each program.

  (ii) Please identify and verify each and every program under all asset families of which PG&E has not developed a Key Performance Indicator.

ANSWER 7

The Indicated Producers_002-Q099 question and response specifically addressed Chapter 6 assets relating to Measurement and Control (M&C) and Compression and Processing (C&P). Each of the Asset Management Plans submitted in response to TURN 001, Q01 addresses asset health condition. (See 2015 GT&S Rate Case Supplemental Testimony, Attachment B, Attachments 6 through 11.) They do not all address asset health thresholds in the same manner as discussed in the Asset Management Plans for M&C and CMP.

(a) For the M&C and C&P assets, as stated in response to Indicated Producers_002-Q92(a) and Q92(f), PG&E plans to develop the methodology and the thresholds during the 2015 Gas Transmission and Storage (GT&S) rate case period with the long term objective that the health thresholds will be routinely applied to the assets. Once developed, the health thresholds will be included in the Asset Management Plans for the Compression and Processing and Measurement and Control Assets. The use of health thresholds is part of the evolution of the asset management plans.

    The response to Indicated Producers_002-Q099 does not include a subpart (f) and it does not include the statement, "PG&E plans to implement the asset health thresholds once they are developed. They will be defined in the Asset Management Plans."

(b) As stated in the 2015 GT&S testimony, Chapter 2, page 2-14, lines 9 through 12, PG&E currently uses Key Performance Indicators (KPI's); KPI's can be found in Section 4 of the various Asset Management Plans. See the response to TURN_001-Q01, attachments Atch06 and Atch08CONF through Atch11CONF for copies of the relevant Asset Management Plans. Indicated Producers_002-Q099 specifically addressed KPI's for the asset health scoring for the M&C and C&P asset families. As previously indicated in IP_002-Q099, the KPI's and the data capture to support the KPI's for asset health scoring will be developed during the 2015 GT&S rate case period. The KPI's will be included in the next revision to the Asset Management Plans for the M&C and C&P assets.

EXHIBIT JAL/CDF-7

GTS-RateCase2015_DR_IS_07-Q002
GTS-RateCase2015_DR_IS_07-Q003

PACIFIC GAS AND ELECTRIC COMPANY
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Data Response

PG&E Data Request No.:	IndicatedShippers_007-02		
PG&E File Name:	GTS-RateCase2015_DR_IndicatedShippers_007-Q02		
Request Date:	July 10, 2014	Requester DR No.:	No. 7
Date Sent:	July 24, 2014	Requesting Party:	Indicated Shippers
PG&E Witness:	Various	Requester:	Evelyn Kahl

QUESTION 2

On Page 1-10 Lines 21 and Lines 24 to 25, PG&E states that it "used industry benchmarking … to identify the appropriate level of residual risk and the appropriate pace to achieve the desired level of risk reduction."

(a) What is the numeric and quantified "desired level of risk reduction" that PG&E identified through industry benchmarking?

(b) What is the numeric and quantified "desired level of risk reduction" that is PG&E's goal to achieve by December 31, 2017?

(c) Did PG&E calculate an overall "desired level of risk reduction" as described on Page 1-10 Line 25?

(i) If the answer is "yes," please provide in electronic format all supporting data, analysis, models, and workpapers that PG&E relied on to calculate the desired level of risk reduction.

(d) Please provide a quantitative estimate of the residual risk balance.

(e) Has PG&E determined the total impact on risk reduction using the "Heat Map" and the risk estimation methodology as described in its Risk Management Procedure (Procedure No. RMP-01, Revision 8, provided in response to IP-2-85 (Confidential Attachment 1) and the Risk Evaluation Tool (Provided in response to IP-2-003, Attachment 1)?

(i) If the answer is "yes," please provide all supporting data, analysis, models, and workpapers PG&E relied on to make that determination.

(ii) If the answer is "no," has PG&E performed any empirical analysis of the risk reductions of its proposed mitigation programs?

(A) If the answer is "yes," please provide all supporting data and analysis, including all models, and workpapers PG&E used.

(f) If PG&E has not made any empirical determinations of the risk reduction benefits of its proposed programs, explain the analytical basis by which PG&E selected the specific programs with which it would "balance" other objectives, such as affordability and ability of ratepayers to absorb rate increases?

(g) What is PG&E's definition or understanding of "desired level of risk reduction" as used in the testimony on Page 1-10 Line 25?

(i) Does PG&E's definition or understanding of "desired level of risk reduction" differ from PG&E's explanations provided in the answers to Indicated Shippers' Questions 02-03(a) and 02-16(e)? If yes, please explain the differences in detail.

(h) What is PG&E's definition or understanding of "the appropriate level of residual risk" as used in the testimony on Page 1-10 Line 25?

(i) What is the numeric and quantified "appropriate level of residual risk" that PG&E identified through industry benchmarking?

(j) What is the numeric and quantified "appropriate level of residual risk" that is PG&E's goal to achieve by December 31, 2017?

ANSWER 2

(a) PG&E did not identify a "desired level of risk reduction" through industry benchmarking. PG&E used industry benchmarking to identify best practices. PG&E also does not numerically quantify risk reduction on a system level. PG&E forecasted risk reductions that represent an appropriate balance of providing the greatest level of risk reduction in the shortest amount of time that can be accommodated based on resource and execution constraints.

(b) PG&E also does not numerically quantify risk reduction on a system level. Chapters in testimony discuss, for specific programs, the relative amount of risk and the pace at which PG&E will address that risk. See the 2015 GT&S testimony Chapters 4A, 4B, 5, 6, and sections C-1 and C-2 in Chapter 7 for examples of the relative amount of risk and pace of risk reduction for specific programs..

(c) See response to part (b) above.

(d) PG&E does not quantify a residual risk balance at a system level. To see risks ranked and estimated risk reduction, see the Risk Register presented in GTS-RateCase2015_DR_TURN_001-Q01Atch03CONF.

(e) The heatmaps do not provide a total quantified level or risk reduction; however, it is a visual representation of our risk portfolio. Risk is reduced as they move toward the bottom left quadrant of the heatmap. Risk Management Procedure RMP-01 is not used explicitly in the development of the enterprise risk heat maps. Rather, RMP-01 is used specifically for determining transmission pipe segment risk to prioritize integrity management work. Further, RMP-01 is using a relative risk methodology and as such cannot be used to quantify risk reduction.

(f) See response to part (e) above.

(g) There is no definition to a specific "desired level of risk reduction". PG&E aims to provide the greatest level of risk reduction in the shortest amount of time while considering resource and execution constraints. See response to GTS-RateCase2015_DR_IndicatedProducers_004-Q01, part (a), where a discussion on risk tolerance is referenced.

   i. It does not differ from the explanation provided in Indicated Producers _002-Q003 part (a) and Q016 part (e).

(h) "The appropriate level of residual risk" is the level of risk that PG&E is willing to accept given a comprehensive risk assessment of its gas transmission and storage assets and inputs from stakeholders and subject matter experts while considering constraints. The determination of the appropriate level of risk tolerance has not been accomplished at this point by PG&E or other stakeholders.

(i) PG&E does not numerically quantify residual risk at a system level. Chapters in testimony discuss, for specific programs, the pace at which PG&E proposes to mitigate associated risk. See the response to GTS-RateCase2015_DR_IndicatedProducers_002-Q003, part (a)(iii), where specific examples in testimony of the relative amount of risk and pace of risk reduction are referenced.

(j) See response to part (h) and part (i) above.

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PG&E Data Request No.:	IndicatedShippers_007-03		
PG&E File Name:	GTS-RateCase2015_DR_IndicatedShippers_007-Q03		
Request Date:	July 10, 2014	Requester DR No.:	No. 7
Date Sent:	July 24, 2014	Requesting Party:	Indicated Shippers
PG&E Witness:	Bennie Barnes	Requester:	Evelyn Kahl

QUESTION 3

PLEASE NOTE THIS QUESTION SEEKS CLARIFICATION ABOUT PG&E CONFIDENTIAL MATERIAL

In regards to PG&E's document provided in TURN_001-Q01 Confidential Attachment 11, PG&E Transmission Pipe Asset Management Plan (AMP), Document GP-1101:

(a) Figure 7 on Page 20 of the Transmission Pipe AMP shows a "heat map" that plots current risks with the IDs TRA1 – TRA7. Are these the same risks as listed in Table 2 on page 19?

(i) If the answer is "no," please identify the risks that are plotted in Figure 7.

(b) Please provide the actual numeric CoF values, LoF values, and total risk scores (LoF x CoF) for the current risks TRA1 – TRA12 listed in Table 2, as calculated by PG&E.

(c) Why do the Risk IDs labeled TRA8 – TRA12 not appear on the heat map on page 20? Did PG&E calculate risk scores for TRA8 – TRA12?

(i) If the answer is "yes," please provide the risk scores for these risks.

(ii) If the answer is "no," please explain why not.

(d) Please provide the estimated post-mitigation CoF values, LoF values, and risk scores for each of the risks, TRA1 – TRA12 that PG&E has calculated based on the strategies and initiatives shown in Sections 6.1 and 6.2 of this AMP.

(i) If any of the risks TRA1 – TRA12 are not addressed in the strategies and initiatives section, please identify them and explain why they are not addressed.

(e) Please provide the forecast budget expenditures to mitigate each of the risks TRA1 – TRA12 for each year of the period 2014 – 2018, as developed for the AMP. For each budget expenditure, please provide in electronic format all supporting data, analysis, and workpapers showing how PG&E determined the specific budgeted risk expenditures are consistent with PG&E's balancing of the risk reductions provided by the mitigation measures to address these risks, against the limited ability of customers to absorb rate increases

(f) Please identify all changes to the proposed budget expenditures for TRA1 – TRA12, as developed in this AMP, with the proposed budgets to address these risks that are presented in PG&E's testimony. For each budget difference, explain why PG&E's testimony presents a different budget estimate than in the AMP, and the effect of the identified budget changes on the post-mitigation risk scores.

ANSWER 3

(a) Yes, the risks shown in Table 2 on page 19 of GP-1101 are the same as those shown in Figure 7 on page 20.

i) Not applicable. Please see PG&E's response to Part (a) above.

(b) Please refer to Data Request Number TURN_001-Q01Atch03 for the numeric Consequence of Failure (CoF) values, Likelihood of Failure (LoF) values, and total risk scores calculated for the 2013 Session D. Numeric CoF, LoF, and total risk score values can be found on the *Summary Risk Scores* tab in columns D, K, and N, respectively. 2013 Session D risks include TRA1 – TRA7.

(c) Risks TRA8 – TRA12 do not appear in Figure 7 on page 20 because these risks were added to the Transmission Pipe Risk Register after the 2013 Session D and after publication of GP-1101 in July 2013.

i) Not applicable. Please see PG&E's response to Part (c).

ii) PG&E did not calculate risk scores for TRA8-TRA12 in the 2013 Session D or in the publication of the 2013 Transmission Asset Management Plan because these risks were identified after Session D and right before the publication of the Transmission Asset Management Plan. By summer 2013, Gas Operations was going to adopt a new Risk Evaluation Tool (RET2) from Enterprise Operational Risk Management and planned to use that model to score any added risks post 2013 Session D.

(d) PG&E understands "estimated post-mitigation CoF values, LoF values, and risk scores" to mean Forecasted Risk. PG&E did not calculate Forecasted Risk for any risks in the 2013 Session D.

i) Section 6.1 of GP-1101 (pages 31-37), *Strategies and Initiatives*, describes the five-pronged approach to asset management, including Threat / Risk Analysis, Monitoring and Preventative Maintenance, Integrity Assessments, Mitigation, and Emergency Preparedness and Response. Each program description lists the threats identified/mitigated. In addition, Figure 4-5 on page 4-16 of the 2015 Gas Transmission and Storage (GT&S) Rate Case testimony shows the mitigations/programs for each threat/risk category.

(e) PG&E prepared budget forecasts for each mitigation program, as shown in Section 6.2 of GP-1101 (pages 37-44). To see how each mitigation program impacts risks and threats, please refer to Figure 4-5 on page 4-16 of the GT&S Rate Case testimony. For supporting information explaining how the 2014-2018 portfolio was developed, please refer to PG&E Data Request Number TURN_001-Q01, Part C.

(f) PG&E prepared budget forecasts for each mitigation program, as described in PG&E Data Request Number TURN_001-Q01, Part C. The results of this process is reflected in Section 6.2 (pages 37-44) of GP-1101 as well as Figure 4-5 on page 4-16 of the GT&S Rate Case testimony. PG&E understands "post-mitigation risk scores" to mean Forecasted Risk. PG&E did not calculate Forecasted Risk for any risks in the 2013 Session D.

EXHIBIT JAL/CDF-8

GTS-RateCase2015_ORA_17-Q002, Att. 1.

PG&E Gas Risk Register Reference for Consequence.

Gas Operations' first risk register was published in 2013. The formulas behind the final result, especially for consequences of failure, require some explanation to understand. This fact sheet walks through the steps that result in the final score for consequence of failure.

1. Establish Consequence Scores.

PG&E chose 7 scores, numbered 1 through 7, with 7 being highest consequence and 1 being lowest consequence, that can be applied to each category of consequence. For each category, a score is determined based on guidance provided (see the table below for examples of the guidance provided). For example, a health and safety score of 7 is "catastrophic", and is defined as resulting in an event that causes loss of multiple lives.

Categories	Examples from the Range of Consequence Scores (1 – 7)
Safety	1 - Very low population and minor injury; 3 – Class 2 location and PG&E employees often in close proximity with threat to one member of public requiring extended medical treatment; 7 – imminent and inevitable threat to lives
Regulatory Compliance	2 – Few or no regulatory complaints/citations expected; 4 –a warning letter; a notice of non-compliance or notice of violation; 6 – regulatory penalty or legal action including incarceration or large fines, non-compliance is system-wide
Environmental Impact	3 – less than <0.1 acre environmental damage; 5 – hazardous material release to water used by humans or livestock; 7 – non-reversible impact
Reliability	1 – local disruption (10 residents without gas for 2 non-peak hours); 4 – failure resulting in low pressure at a localized scale with a value of service equivalent to $7 - $40 million
Reputation	3 – local media coverage; 5 – less than one week of national and international media coverage; 7 – more than 6 months of national and international media coverage
Direct Financial Damage	1 – less than $30k; 5 - $7 - $40 m; 7 – greater than $250 million

2. Rank Health and Safety Scores Higher than Financial Outcome Scores

In this step, we apply an adjustment to assure that the Health and Safety consideration is never outweighed by Financial consideration.

In the risk example below, TRA-6, the risk of excavation damage, the Financial Risk is ranked a "3". On the surface, it appears that this score is less than the Health and Safety score, which is "6". However if risk "X" had a Health and Safety score of "3" and a Financial score of "6" with all other scores the same, TRA-6 and Risk "X" would be ranked equally in total, which would not recognize the higher Health and Safety risk associated with risk TRA-6.

To prevent this situation from occurring, when a risk like TRA-6 is entered into the risk register, the system always adjusts the Financial score to 6. This step assures that risks with a Health and Safety score higher than the Financial score are always ranked higher in total because the overall score now will always be higher than a risk with a lower Health and Safety, but higher Financial score So now, our scores for TRA-6 are what we see in (red) below.

Example: Risk TRA-6. The risk of mechanical damage to the pipeline.

Causes might include:
- Incorrect mark and locate
- Not following instructions
- Inadequate depth of cover

Consequence Scores:

Health & Safety = 6 (6)
Regulatory Compliance = 5 (5)
Environmental Impact = 5 (5)
Reliability = 5 (5)
Reputation = 6 (6)
Financial = 3 (6)

3. Scale consequences logarithmically

In this step, risk consequence scores are converted to a logarithmic scale in order to better differentiate among risks. To convert the one through seven linear scoring to a non-linear equation, the following formula is applied to each of the six consequences:

Health & Safety = 0.000455948900966988*EXP(1.7569 x 6)

Health and Safety =17.25790304

The formula is very typical to determine a slope of a tangent line (e.g. a non-linear equation). EXP is "E" to the power, in this case to the power of 1.7569 x 6. "E" is a constant in math and is approximately 2.718. This formula was tested using the dollar values associated with the Reliability consequences. Applying the same formula as we did above, the scores for Risk TRA-6 are now:

Health & Safety =17.25790304
Regulatory Compliance = 2.978352174
Environmental Impact = 2.978352174
Reliability = 2.978352174
Reputation = 17.25790304
Financial = 17.25790304

4. Weight Consequences

Results up to this point, with the exception of the prioritization of Health and Safety over Financial outcomes are equally weighted. PG&E weights the results consistently with overall corporate objectives to provide safe, reliable and affordable service. Here are the weightings:

Weight	Risk Consequence Category	Weight
Safety (40%)	Health and Safety	30%
	Regulatory Compliance	5%
	Environmental Impact	5%
Reliability (30%)	Reliability	25%
	Reputation	5%
Financial (30%)	Financial	30%

Here is the calculation using the green number from step 3, again for Health and Safety:

17.25790304 x .3 = **5.177370913**

The weighting is applied to the scores for each of the 6 consequence categories:

Health & Safety = **17.25790304** x .30 = **5.177370913**
Regulatory Compliance = 2.978352174 x .05 = **0.148917609**
Environmental Impact = 2.978352174 x .05 = **0.148917609**
Reliability = 2.978352174 x .25 = **0.744588044**
Reputation = 17.25790304 x .05 = **0.862895152**
Financial = 17.25790304 x .30 = **5.177370913**
Total = *12.26006024*

5. Prioritize Health and Safety

The final step is to apply an additional adjustment to assure that Health and Safety receives top priority over all other consequences. For example, if a particular threat was scored with a Health and Safety consequence of 5 in Step 1 (normalized score of 2.95) while all other consequences scored a 1, the weighting in Step 4 would produce an overall combined consequence score of 0.895 which corresponds to a category 4 Health and Safety consequence. Translating this to words using the PG&E risk matrix, this would mean that because there are no significant consequences aside from Health and Safety, the overall consequence of the event would be downgraded from indicating "threat of permanently incapacitating injury to one member of the public or imminent threat of life to one employee" (the outcome associated with an initial Health and Safety score of 5 from Step 1) to "threat of injury to one member of public requiring extended medical treatment" (the outcome associated with an initial Safety score of 4 in Step 1). This result does not prioritize Health and Safety appropriately.

To address this potential scenario, the scores from Step 4 are divided by .3, effectively increasing all of the final scores so that the total consequence score is never reduced below the Health and Safety value. Here's the calculation using the result in purple from step 4 for the Health and Safety risk:

Health and Safety = **5.177370913/.3**

Final Health and Safety Score = 17.257

This step does not change the ranking order of the risks. Here are the results:

Health & Safety =	17.25790304	Reliability =	2.481960145
Regulatory Compliance =	0.496392029	Reputation =	2.876317174
Environmental Impact =	0.496392029	Financial =	17.25790304

Total = **40.8668674**

These adjustments are applied universally across all risks so that the priority of Health and Safety is consistently emphasized.

EXHIBIT JAL/CDF-9

A09-09-013, Direct Testimony of Roy Surges, p. 6-8

Application: 09-09-
(U 39 G)
Exhibit No.:
Date: September 18, 2009
Witness: Various

PACIFIC GAS AND ELECTRIC COMPANY

2011 GAS TRANSMISSION AND STORAGE RATE CASE

PREPARED TESTIMONY

PACIFIC GAS AND ELECTRIC COMPANY
2011 GAS TRANSMISSION AND STORAGE RATE CASE

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TABLE 6-5
PACIFIC GAS AND ELECTRIC COMPANY
PIPELINE INTEGRITY, MWC-98 (2009-2014)
MILLIONS OF $ (NOMINAL)

Line No.	Major Work Category	2009	2010	2011	2012	2013	2014	Total 2011-2014
1	Pipeline Integrity, MWC-98	19.6	23.1	23.0	22.0	15.0	11.0	71.0

3. Pipeline Safety and Reliability, MWC-75 (Roy A. Surges)

This category includes capital costs of improving the safety and reliability of the gas transmission pipeline system. Examples of expenditures in this category include replacing high-risk, high-consequence pipeline segments and pressure regulating facilities identified by PG&E's Pipeline Risk Management Program. This MWC also includes expenditures necessary for PG&E to comply with the many subparts in 49 CFR, Part 192, which govern the construction, maintenance and operation of natural gas transmission pipelines.

The annual capital expenditures for MWC-75 range from $15.3 million in 2011 to $43.0 million in 2014. Reliability-based investment is forecast to increase as capital spending in Pipeline Integrity Management decreases. Pipeline integrity information obtained from inspection results will be included in risk assessments and be used to prioritize pipeline safety and reliability investments. Table 6-6 summarizes the capital expenditure forecast for Pipeline Safety and Reliability, MWC-75.

TABLE 6-6
PACIFIC GAS AND ELECTRIC COMPANY
PIPELINE SAFETY AND RELIABILITY, MWC-75 (2009-2014)
MILLIONS OF $ (NOMINAL)

Line No.	Major Work Category	2009	2010	2011	2012	2013	2014	Total 2011-2014
1	Safety and Reliability	12.4	17.6	11.6	27.5	36.0	39.0	114.1
2	Cathodic Protection	3.1	3.1	2.0	2.2	2.3	2.4	8.9
3	Regulating Stations	(0.3)	1.0	1.3	1.4	1.5	1.6	5.8
4	Small Pipeline Projects < $1,000,000	7.7	2.7	0.4	–	–	–	0.4
5	Total Capital Expenditures, MWC-75	22.9	24.4	15.3	31.1	39.8	43.0	129.2

The Pipeline Safety and Reliability MWC-75 is segmented into Planning Orders to better categorize projects by asset class and work type. A description of each Planning Order follows.

a. Pipeline Safety and Reliability Planning Orders

These projects involve replacing existing portions of PG&E's gas pipeline system to maintain safety, integrity, and reliability. Projects are driven by either regulatory compliance or high system risk.

(1) Regulatory Compliance, Class Location Changes

PG&E is experiencing an increase in the number of gas transmission pipeline replacement projects due to federal economic stimulus driven growth and urban development toward previously rural pipeline rights-of-way. 49 CFR, Part 192, prescribes minimum safety requirements for pipeline facilities and the transportation of natural gas. These regulations set specific pipeline design factors for safety depending on the number of occupied buildings and dwellings in close proximity to a gas transmission pipeline. There are four levels of class location or class location units, defined as Class 1, 2, 3 and 4. The class designation indicates what safety level must be applied, with Class 4 representing the highest level of safety. As population density and development increase near PG&E's pipelines, the pipeline class location increases. Pipeline owners/operators are required to increase the designed factor of safety within the affected pipeline segment(s). The pipeline safety factor can be increased by one of three ways:

1. Reducing the maximum allowable operating pressure of the pipeline. This results in a corresponding reduction in pipeline throughput and capacity. PG&E rarely decreases the maximum allowable operating pressure of a pipeline because capacity demands will seldom allow it.
2. Re-qualifying or retesting the pipeline at higher pressures to verify structural integrity, a process called pressure-testing. Pressure-testing requires the pipeline to be removed from service and pressure tested with water or another medium. This procedure is only applicable if the pipeline was never

hydro-tested to its maximum design and the pipeline can continue to operate at the same pressure with the higher safety factor.

3. Installing a new segment of gas pipeline that is tested and qualified to operate at the desired pressure within the new and anticipated future class location area.

Typically, when a pipeline class location increases due to development, PG&E will either pressure-test the pipeline to ensure adequate safety or install a new pipeline segment to meet both the safety requirements and maintain or increase capacity.

Development and urban expansion in the Bay Area, and particularly in the Bakersfield area, will require significant investment in pipeline replacements, due to class location changes per CFR 192.611. An example of a Class Location Change project is:

- 2012 – Replace 10,080 feet of Line 300A in Bakersfield due to a Class Location change. $6.0 million.

(2) Pipeline Risk Management Program

In 1998, PG&E developed a pipeline Risk Management (RM) Program to assess the risk of every segment of gas transmission pipeline within PG&E's system. The Chief of the Utilities Safety Branch at the California Public Utilities Commission (CPUC or Commission) approved the program on April 20, 2000.

Pipeline risk is determined by assessing two factors: (1) probability or likelihood of failure; and (2) local consequence of failure.

The probability of a pipeline failure depends on various physical characteristics such as diameter, wall-thickness, operating pressure, year installed, pipeline condition reports, method of construction, type of coating, depth of cover, vulnerability to third-party damage, and environmental factors such as proximity to earthquake faults and potential landslides. Factors used to determine consequences include: population density, impact zone of the pipeline, types of structures in proximity to the pipeline, environmental impacts (water

EXHIBIT JAL/CDF-10

GTS-RateCase2015_DR_IS_04-Q023

PACIFIC GAS AND ELECTRIC COMPANY
Gas Transmission and Storage Rate Case 2015
Application 13-12-012
Data Response

PG&E Data Request No.:	IndicatedProducers_004-Q23		
PG&E File Name:	GTS-RateCase2015_DR_IndicatedProducers_004-Q23		
Request Date:	June 6, 2014	Requester DR No.:	004
Date Sent:	June 19, 2014	Requesting Party:	Indicated Producers
PG&E Witness:	Louis Krannich (a,e) Jim Howe (b-d)	Requester:	Evelyn Kahl/ John McIntyre/ Kenneth Sosnick

SUBJECT: GENERAL QUESTIONS WITH NO CORRESPONDING PG&E TESTIMONY CHAPTER

QUESTION 23

What role does a budget play in determining which projects to undertake based on Risk Score prioritization?

(a) Did PG&E use a budget to determine which projects to propose in this Application? If so, please provide all drafts and modifications prior to the budget finalization.

(b) Under a hypothetical situation in which PG&E's revenue requirement could not exceed $1 billion, which projects proposed in the GT&S Application would PG&E still plan to complete and which projects would PG&E decide not to undertake?

(c) What method did PG&E use to reach the conclusion above in 04-23(b)?

(d) What is the reasoning for how PG&E prioritized the projects in the conclusion above in 04-23(b)?

(e) Please explain any cost-benefit analysis as it is associated with both risk and system reliability for the completion of each project. For example, some projects may have high risk, medium risk, or low risk concerns, some projects may have high cost, medium cost, or low cost, and some projects may have high system reliability, medium system reliability, and low system reliability concerns. How does PG&E decide what projects to complete when considering such factors?

ANSWER 23

(a) PG&E did not use a budget to determine which projects to propose in this application. PG&E is presenting a forecast to achieve the greatest amount of risk reduction for the investment made given the constraints to perform the work and after determining whether there is a less costly, or more affordable, way to achieve the same level of risk reduction. In preparing the whole portfolio, PG&E considered risk reduction and affordability. PG&E's final product represents a portfolio of work reduced in scope and cost from initial proposals, but that still sufficiently addresses the most important risks. The development of the final portfolio of work was an iterative process and as the forecast was refined, rate impacts were calculated and assessed. For additional detail about how the forecast was refined see PG&E's response to TURN_001-Q01.

(b) PG&E would need to perform a risk based reprioritization of its proposed portfolio of work based on reduced funding levels in order to determine the specific impacts that would result. This analysis has not been completed.

(c) See response to (b) above.

(d) See response to (b) above.

(e) The forecasts for each of the programs in this rate case include cost-benefit analyses that address safety risk as well as system reliability. For each program, PG&E describes the factors it weighed in developing the scope and pace of its programs. See Chapters 4 through 12 in testimony for the 2015 Gas Transmission and Storage rate case.

EXHIBIT JAL/CDF-11

GTS-RateCase2015_DR_IP_02-Q085, Att. 1- Redacted

[redacted]

PACIFIC GAS AND ELECTRIC COMPANY

GAS OPERATIONS

PUBLIC SAFETY & INTEGRITY MANAGEMENT

Risk Management Procedure

Procedure No. RMP-01
Revision 8
Risk Management

Gas Transmission Integrity Management Program
for PG&E and Standard Pacific Gas Line, Inc.

Prepared By: [redacted] Date: 7/10/12
[redacted] Risk Management Supervisor

Concur: [redacted] Date: 7/25/12
[redacted], Integrity Management Engineering Manager

Concur: Date: 7-16-12
Bennie Barnes, Director, Transmission Integrity Management

Concur: Date: 7-27-12
Sanford Hartman, Vice President, Managing Director, Law

Approved By: Roland Trevino Date: 7/29/2012
Roland Trevino, Vice President, Public Safety & Integrity Management

Rev. No.	Date	Description		Prepared By	Approved By	Approved Manager, System Integrity	
0	11/13/01	Initial Issue		[redacted]	[redacted]	[redacted]	
1	1/8/03	Revised as shown					
2	6/29/04	Revised as shown					
3	11/16/04	Revised as shown					
4	6/9/05	Revised as shown					
5	10/31/05	Revised as shown					
6	1/10/11	See Change Form					
Rev No	Date	Description	Prepared by	Manager of Integrity Management	Director of Integrity	Vice President, Managing Director, Law	Vice President, Public Safety & Integrity Management
7	3/26/12	See Change Form	[redacted]	[redacted]	NA	SLHB	RIT4
Rev No	Date	Description	Prepared by	Manager, Integrity Management Engineering	Director, Transmission Integrity Management	Vice President, Managing Director, Law	Vice President, Public Safety & Integrity Management
8	7/29/12	See Change Form	[redacted]	[redacted]	B2BY	SLHB	RIT4

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1.0 PURPOSE

The purpose of this procedure is to describe the process for maintaining the Risk Management Program (RMP) and complying with the requirements for risk calculations as part of PG&E's Transmission Integrity Management Program (TIMP) and Distribution Integrity Management Program (DIMP), which are described in RMP-06 and RMP-15, respectively.

2.0 SCOPE

2.1 General

The Risk Management Group is responsible for managing risk within the scope of this procedure. The Risk Management Group shall establish the risk of each pipeline facility using methodologies that are:

- consistent with industry practice
- acceptable to regulatory agencies
- appropriate to PG&E's gas facilities
- in conformance with this procedure

The Risk Management Group shall apply this procedure, and as appropriate, partner with Pipeline Engineering, the System Integrity Group and other internal organizations to apply this procedure in an effort to manage risk.

In accordance with IMP procedures, risk information shall be communicated to management and other appropriate PG&E personnel for project planning, risk mitigation, inspection planning, and regulatory reporting. Per RMP-06, risk for each pipeline segment shall be calculated annually or as required by RMP-15.

2.2 Transmission

This procedure applies to all PG&E and Standard Pacific Gas Line, Inc. (StanPac):

- Gas Transmission Pipeline Facilities
- Regulating Station Facilities
- PG&E-defined Gas Gathering-Local Transmission (GG-LT) Lines

2.3 Distribution

This procedure applies to all PG&E-defined distribution piping, equipment, and appurtenances operating above 60 psig for the assessment of risk per RMP-15.

3.0 INTRODUCTION

The risk management process gathers reviews and integrates data to calculate risk, prioritizes preventive and mitigative measures, and monitors for operational changes that may require additional actions. This process is applied annually to assure the ongoing integrity of all pipelines specified in Section 2.

RMP-01 describes the calculations for overall risk which is the product of the likelihood of failure (LOF) and consequence of failure (COF) potentially arising from the nine pipeline threats as defined in ASME B31.8S-2004. The nine threats are organized by failure mode grouping. The threats and the associated RMPs that contain the threat algorithms are as follows.

3.1 Time-Dependent Threats

1. External corrosion (EC): see RMP-02
2. Internal corrosion (IC): see RMP-02
3. Stress corrosion cracking (SCC): see RMP-02

3.2 Stable Threats

1. Manufacturing related defects (M): see RMP-05
2. Construction, including welding/fabrication-related (C): see RMP-05
3. Equipment failure (E): see RMP-19

3.3 Time-Independent Threats

1. Third party damage (TPD): see RMP-03
2. Incorrect operations (IO): see to RMP-19
3. Weather-related and outside force (WROF): see RMP-04

Where Manufacturing and Construction are handled together, they are designated as M&C.

4.0 ROLES AND RESPONSIBILITY

Specific responsibilities for ensuring compliance with this procedure are as follows:

Title	Reports to:	General Responsibilities
Manager of Risk Management Engineering	Director of Transmission Integrity Management	• Review and approve selection of Steering Committee Chairperson and membership
Supervisor of Risk Management	Manager of Risk Management Engineering	• Supervise completion of work (schedule/quality) • Monitor compliance with procedure and take corrective actions as necessary • Assign qualified individuals • Ensure training of assigned individuals

Title	Reports to:	General Responsibilities
Steering Committee Chairperson	Various	• Arrange meetings • Review procedure with steering committee per RMP-01 • Provide meeting minutes • Ensure action items are completed
Steering Committee Members (Subject Matter Experts)	Various	• Attend meetings as requested by Steering Committee Chairman • Review and direct procedure
Risk Management Engineers	Supervisor of Risk Management	• Perform calculations per procedure

5.0 TRAINING AND QUALIFICATIONS

5.1 Training

Specific training to ensure compliance with this procedure is as follows:

Position	Type of Training	How Often
Supervisor of Risk Management	Procedure review of RMP-01	• Upon initial assignment • Once each calendar year
Steering Committee Chairperson	Procedure review of RMP-01	• Upon initial assignment • As part of steering committee meeting once each calendar year • As changes are made to the procedure
Steering Committee Members (Subject Matter Experts)	Steering Committee requirements of RMP-01	• As part of steering committee meeting once each calendar year
Risk Management Engineers	Procedure Review of RMP-01 and RMP-06	• Upon initial assignment • Once each calendar year • As changes are made to the procedure

5.2 Qualifications

See RMP-06 and RMP-15 for qualification requirements.

6.0 STEERING COMMITTEES

For each major component of the risk management program, a Steering Committee shall be established to provide technical review and input to the program. The Steering Committees are as follows, with threat assignments in parentheses:

- Time-Dependent Threats (EC, IC, SCC)
- Manufacturing and Construction (M&C)
- Equipment Failure (E)
- Third-Party Damage (TPD)
- Incorrect Operations (IO)
- Weather-Related and Outside Forces (WROF)
- Consequence of Failure (COF)

The first six steering committees are collectively the Likelihood of Failure committees. The threats of EC, IC, and SCC are addressed together by the Time-Dependent Threats steering committee. The threats of Manufacturing and Construction are addressed together by the M&C steering committee. The other threats have separate steering committees.

6.1 Steering Committee Requirements

Requirements for the Steering Committees are as follows:

6.1.1 Steering Committee Chairpersons

For each steering committee, the Manager of Risk Management, with the concurrence of the Supervisor of Risk Management, shall assign a Steering Committee Chairperson, except as noted by RMP-15. The Steering Chairperson is responsible for the adherence to this procedure.

6.1.2 Steering Committee Members

The Steering Committees shall be made up of at least five individuals with expertise in the particular subject matter. It is the responsibility of the Supervisor of Risk Management, with the concurrence of the Manager of Transmission Integrity Management, to select individuals with knowledge and experience in the steering committee's subject matter. A list of the current membership shall be documented.

6.1.3 Schedule and Scope

The steering committees shall meet at least once each calendar year to review and approve the methodology used to calculate risk, and to determine whether changes are advisable.

6.1.4 General assignments

At each meeting, the steering committees shall:

- Review the overall process of risk calculations described by this procedure and document their evaluations

- Review the requirements for conducting a steering committee meeting in the appropriate location
- Document the discussions and findings of steering committee meetings in the appropriate location

6.1.5 Specific assignments

Steering Committees shall validate the risk analysis results to assure that the methods used have produced results that are consistent with Company operations.

The LOF Steering Committees shall, at a minimum:

- Review risk algorithm output
- Review relevant performance metrics
- Review relevant industry data
- Review incident reports
- Ensure that pertinent regulatory advisories are included
- Ensure that role of mitigation is appropriately included
- Review weightings within the LOF factors
- Propose and document changes that may be needed in the risk calculation algorithms
- Perform procedures per this document and related documents
- Determine whether any new factors or data sets should be incorporated into the algorithm to better reflect LOF

The COF Steering Committee shall review, at a minimum:

- Risk algorithm output
- Relevant performance metrics
- Relevant industry data
- Incident reports
- Pertinent regulatory advisories
- Weightings within the COF factors
- Changes that may be needed in the risk calculation algorithms
- Relevant procedure per this document and related documents
- Whether any new factors or data sets should be incorporated into the algorithm to better reflect COF

6.2 Algorithm responsibility

The steering committees shall review procedures applicable to the threats as follows:

- **The algorithm for the threats of EC, IC, and SCC** shall be calculated per the direction of the Time-Dependent Threat Steering Committee, as described in RMP-02.
- **The algorithm for the threats of M&C** shall be calculated per the direction of the M&C Threat Steering Committee, as described in RMP-05.

- **The algorithm for the threat of E** shall be calculated per the direction of the Equipment Failure Threat Steering Committee, as described in RMP-19.
- **The algorithm for the threat of TPD** shall be calculated per the direction of the TPD Threat Steering Committee, as described in RMP-03.
- **The algorithm for the threat of IO** shall be calculated per the direction of the IO Threat Steering Committee, as described in RMP-19.
- **The algorithm for the threat of WROF** shall be calculated per the direction of the WROF Threat Steering Committee, as described in RMP-04.
- **The algorithm for the COF** shall be calculated per the direction of the COF Steering Committee, as described in RMP-01.

7.0 Data Gathering

Comprehensive pipeline and facility knowledge is essential to understanding the risk drivers that can affect an HCA segment. No one source of information is sufficient to make a reasonable assessment of risk; therefore, this information is gathered from numerous sources and is integrated for risk assessment. Data elements for each of the nine threat categories are as specified in ASME B31.8S and described in RMP-06.

7.1 Dataset Update

Risk is calculated based on an inventory of assembled datasets which are gathered by a variety of processes and with varying timeframes. New information may include, but is not limited to:

- Changes in surroundings, including population near a pipeline
- Changes to system operating characteristics that could affect safety margins
- The number of customers out of service
- Gas load
- Seismic information from the U.S Geological Survey (USGS)
- Updated environmentally-sensitive areas
- Maintenance, operation and mitigation results

Updates to the datasets are necessary for risk evaluations to reflect the operating conditions of the pipeline. The table below lists the minimum update cycles for data used in the risk assessment process.

Table 1. TABLE 1. UPDATE CYCLES

Category	Data	Minimum Update Interval
Attribute Data	See RMP-06 list	As made available in the company's data systems
Construction Data	See RMP-06 list	As made available in the company's data systems
Operational	Third party dig-ins	As submitted, annually
	Leak reports	As submitted, annually
	Other datasets, per RMP-06	As submitted, annually
Operational (geotechnical or land related)	Seismic (vertical or horizontal ground acceleration)	5 years
	Slope stability	5 years
	Liquefaction	5 years
	Water crossing	10 years
	Water crossing (navigable waterways)	As available
	Seismic (fault crossing)	5 years
	Land base*	As updates are submitted from the company-contracted land base vendor
Other	Electric transmission (internal)	As made available in the company's data systems
	Other (foreign) pipelines/ facilities	As available
	Public awareness information	Annually
Inspection Data	Other per RMP-06	As made available in the company's data systems
	HCA information including identified sites	Annually

* Land base information includes airports, roads, highways, railroads, water crossings (other than navigable waterways), parks, etc.

8.0 RISK DETERMINATION

8.1 Risk

Risk shall be defined as the product of the Likelihood of Failure (LOF) and the Consequence of Failure (COF):

$$RISK = LOF \times COF$$

(Equation 1)

In general, information used to calculate risk is obtained from PG&E's Geographical Information System (GIS). Exceptions are noted within Risk Management procedures. In special cases, updated information is made available from other sources, such as from pipeline engineers, in-line inspection (ILI) reports, corrosion engineers, or district personnel.

8.2 Calculation Methodology

The approach used to calculate risk is a relative risk assessment model. Relative risk values are produced by this methodology. The scoring shall be based on direction from appropriate Steering Committees and performed by the Risk Engineers.

Risk is calculated per this procedure for all pipeline segments. A pipeline segment is defined as a length of contiguous pipeline with the same piping specification, class location, and Integrity Management HCA designation.

Risk values for equipment or appurtenances (including drips, blow downs, stubs, crossties, dual feeds, or other equipment or appurtenances) are not calculated independently since; each appurtenance takes on the risk value calculated for its associated pipe segment, per PHMSA IM FAQ 84. All equipment, appurtenances, and features along the pipeline are a part of the segment and may govern the assignment of points for the entire segment.

Criteria that the steering committees consider significant for determining the threat's LOF and COF are expressed in points. Negative points may be assigned where current assessments confirm pipeline integrity and/or mitigation efforts have reduced susceptibility to a threat. The total value of each LOF shall not be less than zero.

The risk calculation includes these steps:

1. Accumulating data as described in this document and RMP-06
2. Determining LOF for each pipeline segment.
3. Determining COF for each pipeline segment.
4. Calculating risk for each pipeline segment based on the product of LOF and COF, where the LOF of each threat factor has been normalized
5. Review and validation of results

8.3 Likelihood of Failure

Likelihood of failure (LOF) is the relative measure of the probability that a pipe will fail.

The formula for calculating LOF is:

$$LOF = EC + IC + SCC + TPD + WROF + M\&C + E + IO$$

(Equation 2)

where

- The LOF is the summation of the normalized value of the likelihood of failure for each pipeline threat category.
- The likelihood of failure for each pipeline category is based upon individual factors contributing to the likelihood for each mode of failure. These factors are defined as algorithms in separate risk management procedures, as follows:
  - EC, IC, and SCC threat categories are defined per RMP-02
  - TPD threat category is defined per RMP-03
  - WROF threat category is defined per RMP-04
  - M&C threat categories are defined per RMP-05
  - E and IO threat categories are defined per RMP-19.

If new threat categories are identified for the determination the LOF, they will be submitted to the Consequence of Failure Steering Committee for inclusion in the risk calculations.

Threat interaction is acknowledged in the summations of the individual threat scores. Further evaluation for possible threat interaction is done by examination of combinations of certain threat scores.

The values used to determine when additional attention is warranted are set by the steering committee teams using comparable statistics from other pipeline segments and/or other factors.

8.4 Consequence of Failure

Consequence of failure (COF) shall be defined as the sum of the following weighted consequence categories: Impact on Population (IOP), Impact on the Environment (IOE), and Impact on Reliability (IOR).

8.4.1 Weighting

Each of the COF categories shall be weighted in proportion to the impact of a failure. IOP shall be weighted 50%, IOE shall be weighted 10%, and IOR shall be weighted 40%.

$$COF = [0.50(IOP) + 0.10(IOE) + 0.40(IOR)]\ FSF$$

(Equation 3)

where

IOP = Impact on Population (subsection 8.4.2 of this procedure)

IOE = Impact on Environment (subsection 8.4.3 of this procedure)

IOR = Impact on Reliability (subsection 8.4.4 of this procedure)

FSF = Failure Significance Factor (subsection 8.4.5 of this procedure)

The weightings of each of the COF categories are reviewed and approved by the COF Steering Committee. The consequences are expressed in points, as described in subsections 8.4.2, 8.4.3, 8.4.4, and 8.45, below.

8.4.2 Impact on Population (IOP)

The IOP contribution to COF shall be the sum of contributions for the following factors, where the contribution is the assigned points multiplied by the weighting.

A) **Population density in proximity to pipeline factor** (35% weighting)
Points are assigned as follows:

Criteria		Points	Contrib.
Class Location as defined by 49 CFR 192.5	Class 1	10	3.5
	Class 2	40	14
	Class 3	70	24.5
	Class 4	100	35

B) **Pipeline proximity[1] factor** (45% weighting)
Points shall be awarded once per criterion type, but more than one criterion can apply.
Points for each criterion are cumulative and are assigned as follows:

Criteria	Points	Contrib.
Identified sites per RMP-08	100	45
Railroads, BART, and light rail tracks	30	13.5
Highway[2]	40	18
Commercial airports[3]	50	22.5
No feature	0	0

[1] Proximity is defined as the larger of 300 ft radius or the PIR per RMP-08.
[2] Highways are Class 1, 2, and 3 roads as defined in the land base data set.
[3] Airports are as defined in the land base data set.

C) **Impact Zone Factor** (20% weighting)
Points are assigned as follows:

$$\text{Points} = 1 + \pi[(0.69)(OD^2 * MAOP)^{1/2}]^2(1.3X10^{-5}), \text{ not to exceed } 20$$

8.4.3 Impact on Environment (IOE)

The IOE contribution to COF is the sum of contributions for the following factors, where the contribution is the assigned points multiplied by the weighting.

A) **Water crossing factor** (20% weighting).
Points are assigned as follows:

Criteria	Points	Contrib.
Presence of water crossing	100	20
No water crossing	0	0

B) **Environmentally-sensitive area factor** (80% weighting)
Points shall be awarded once per criterion type, based upon proximity* of pipeline, but more than one criterion can apply.
Points for each criterion are cumulative and are assigned as follows:

Criteria	Points	Contrib.
State or national park	70	56
Wildlife preserve	70	56
Navigable waterway	90	72
Other protected area	70	56
No environmentally sensitive area	0	0

*Within 100 yards or PIR (as defined in RMP-08), whichever is greater and unless otherwise noted.

8.4.4 Impact on Reliability (IOR)

The IOR contribution to COF is the sum of contributions for the following factors, where the contribution is the assigned points multiplied by the weighting.

A) **Reliability impact factor** (35% weighting)
Impact on gas load served by PG&E in the event of a pipe failure.
Points are assigned for gas load* as follows:

Criteria	Points	Contrib.
Known gas load	10 + (Gas Load/ 500)**	≤35
Unknown gas load	20	7

* Gas Load (MCF/Day) is the higher of an Average Summer Day (ASD) or an Average Winter Day (AWD), as provided by Transmission System Planning; does not include Abnormal Peak Days (APD).
** Not to exceed 100.

B) **Outage Factor** (55% weighting)
Number of potential services experiencing a gas service outage in the event of a pipe failure based upon the Gas Transmission planning model.
Points are assigned as follows:

Criteria	Points	Contrib.
Known number of customers affected	10 + (number of customers /500)*	≤55
Unknown number of customers affected	20	11

* Not to exceed 100.

C) **Critical Facility Factor** (10% weighting).
If there are multiple critical facilities, only the facility with the highest points is

included in the point total.
Points are assigned as follows:

Criteria	Points	Contrib.
Liquid fuel pipelines[1]	100	10
Other gas pipelines[2]	80	8
Electric transmission lines[1]	80	8
No critical facilities	0	0

[1] Within 30 meters of gas pipeline.
[2] Within 10 meters of gas pipeline.

8.4.5 Failure Significance Factor (FSF)

FSF represents the relative likelihood of leak, rather than rupture, and the existence of wall-to-wall conditions which would make the consequences of a leak more severe. The FSF will be assigned as 1.0 or it can be assigned as 0.5 if the pipe operating stress is less than 20% of SMYS, wall-to-wall paving conditions are verified and meets all the following criteria:

1. Depth of cover is more than 12 inches
2. The pipeline segment is not located within 300 ft. of a switchyard
3. The pipeline segment OD is less than 4.5 inches, **or** the pipe diameter is greater than 4.5" and is not located within 300 feet of an identified site, as defined by 49 CFR Part 192.903
4. The pipeline was installed after 1962 and has a ground acceleration of less than 0.5g.
5. The pipeline was installed after 1962 and has a ground acceleration of 0.2 g or greater and is not in an area susceptible to significant ground movement per Figure A-6: Construction Threat Identification in RMP-16.

9.0 Documentation

The decisions of the threat steering committees shall be documented by meeting minutes that detail the rationale of the algorithm decisions. The minutes shall be maintained within the Risk Management files.

The data used for the risk assessment is contained in the Risk Calculations for a given year (documented in the Risk and Threat spreadsheet).

The results of the risk assessment process shall be documented in the Baseline Assessment Plan (BAP).

The documentation shall be maintained for the life of the facilities in accordance with 49 CFR 192.947.

EXHIBIT JAL/CDF-12

GTS-RateCase2015_DR_ORA_17 -Q005

PACIFIC GAS AND ELECTRIC COMPANY
Gas Transmission and Storage Rate Case 2015
Application 13-12-012
Data Response

PG&E Data Request No.:	ORA_017-05		
PG&E File Name:	GTS-RateCase2015_DR_ORA_017-Q05		
Request Date:	March 3, 2014	Requester DR No.:	ORA-GT&S-17
Date Sent:	April 1, 2014	Requesting Party:	Office of Ratepayer Advocates
PG&E Witness:		Requester:	Jonathan Bromson

SUBJECT: GTS-RATECASE2015_DR_TURN_001- Q01ATCH02, "METHOD FOR CALCULATING WEIGHTED RISKS AND DETERMINING THE HEAT MAP"

QUESTION 5

PG&E states the following: "The likelihood of failure (LoF) is presented as a frequency, which also increases by an order of magnitude for each higher level. The highest frequency is 10 times per year and the lowest is 1/100,000 times per year."

Please explain how PG&E determined the highest and lowest frequency levels of 10 times per year and 1/100,000 times per year for use in its LoF determination.

ANSWER 5

PG&E selected seven different levels of frequencies to use in its risk assessment model because it provides a method to establish the relative ranking of one potential risk versus another potential risk. PG&E selected the frequency of "more than 10 times per year as having the highest score and the frequency of "more than every 10,000 years" as the likelihood with the lowest score[1] based on benchmarking of risk evaluation models used by other companies and frequency of incidents at PG&E. In addition, PG&E's risk management scoring includes five other gradations of potential frequency between these two extremes including (from highest to lowest score):

- One to 10 times per year
- Once every 1 -10 years
- Once every 10 – 100 years
- Once every 100 – 1000 years
- Once every 1,000 -10,000 years

1 See attachment GTS-RateCase2015_DR_TURN_001-Q01Supp01Atch04 Utility Procedure: TD-4011P-01, Publication Date 07/31/2013, Gas Operations Asset Management Systems Risk Management, p. 35.

The categorization of the likelihood a particular threat will cause a specified failure is based upon a combination of expert judgment, experience, and technical knowledge. As such, the categorization, and resulting risk ranking score, is not intended to predict the mathematical probability of that specific failure occurring at any given time, but instead, to establish a relative ranking of the likelihood of failure. Such relative rankings help inform PG&E of which threats likely constitute its highest risks, and as such assists PG&E with making sound decisions regarding operation, maintenance and risk mitigation efforts.

EXHIBIT JAL/CDF-13

GTS-RateCase2015_DR_ORA_17 -Q001

PACIFIC GAS AND ELECTRIC COMPANY
Gas Transmission and Storage Rate Case 2015
Application 13-12-012
Data Response

PG&E Data Request No.:	ORA_017-01		
PG&E File Name:	GTS-RateCase2015_DR_ORA_017-Q01		
Request Date:	March 3, 2014	Requester DR No.:	ORA-GT&S-17
Date Sent:	April 1, 2014	Requesting Party:	Office of Ratepayer Advocates
PG&E Witness:		Requester:	Jonathan Bromson

SUBJECT: GTS-RATECASE2015_DR_TURN_001-Q01ATCH02, "METHOD FOR CALCULATING WEIGHTED RISKS AND DETERMINING THE HEAT MAP"

QUESTION 1

Please describe and explain the process used to determine the 6 specific "consequence categories" which PG&E utilized in its "risk assessment sessions failure scenarios of assets."

a. Did PG&E consider any other categories besides the six chosen?

b. Please provide the definitions of each of the 6 consequence categories, and the methodology PG&E uses to assess the magnitude of consequence in each category (i.e., how PG&E determines how much of a consequence a particular failure scenario has on Health and Safety, Regulatory Compliance, Environmental Impact, Reliability, Reputation, and Direct Financial Damage).

c. At what level of PG&E's organization are the weighting factors approved and given final sign-off before PG&E used them for analysis?

ANSWER 1

The choice of the six specific "consequence categories" was based on benchmarking of risk evaluation models used by other companies.

a. No, PG&E did not consider any other categories besides the six chosen.

b. Refer to Appendix 6, pages 37 – 42, of Utility Procedure TD-4011P-01, Rev. 0 (TURN_001-Q01Supp01Atch04) where the six categories are defined and the magnitude of consequence in each category is described.

c. The weighting factors used in PG&E's risk assessment are Safety (40%), Reliability (30%) and Financial (30%). The Chief Risk and Audit Officer approved the weightings and presented the approach to risk assessment, including the weighted risk evaluation tool, to the company's Risk Policy Committee, which includes

PG&E's most senior officers and the Chief Risk Officer, in March 2012. Since then, the company has revised the tool; however, it maintained the original categories and weightings.

EXHIBIT JAL/CDF-14

GTS-RateCase2015_DR_ORA_17-Q006

PACIFIC GAS AND ELECTRIC COMPANY
Gas Transmission and Storage Rate Case 2015
Application 13-12-012
Data Response

PG&E Data Request No.:	ORA_017-06		
PG&E File Name:	GTS-RateCase2015_DR_ORA_017-Q06		
Request Date:	March 3, 2014	Requester DR No.:	ORA-GT&S-17
Date Sent:	April 1, 2014	Requesting Party:	Office of Ratepayer Advocates
PG&E Witness:		Requester:	Jonathan Bromson

SUBJECT: GTS-RATECASE2015_DR_TURN_001- Q01ATCH02, "METHOD FOR CALCULATING WEIGHTED RISKS AND DETERMINING THE HEAT MAP"

QUESTION 6

Please explain how PG&E's ERM department "set" the "weighted scoring method" and determined the specific "weighing factors" listed in Table 2, "Weighing factors of the consequence categories."

Please provide support for the statement: "Most failure scenarios have consequences in more than one consequence category."

ANSWER 6

PG&E's Risk Evaluation Tool was designed to produce a priority list of risks that are aligned with the company's objectives. This meant the tool needed to place an emphasis on the top risks that could threaten PG&E's ability to deliver safe, reliable, and affordable gas and electric service. To achieve this, Safety related consequences in the risk register, and listed in Table 2 of the Method for Calculating Weighted Risks and Determining the Heat Map, are weighted at 40% by adding Health and Safety at 30%, Environment at 5%, and Regulatory Compliance at 5%. Reliability consequences are weighted at 30% between Reliability at 25% and Reputation at 5%, and finally, Financial consequences are weighted at 30%. The weighting of these factors mirror the weighting of the same factors included in PG&E's short term incentive plan (STIP) (Safety – 40%, Reliability – 30%, and Financial – 30%), which also are aligned with management's goal of delivering safe, reliable and affordable gas and electric service

"Most failure scenarios have consequences in more than one consequence category" means that most risks have a consequence score across all six categories (Safety and Health, Environment, Regulatory Compliance, Financial, Reputation, and Reliability.) In the example introduced in PG&E's response to ORA_017-Q04, risk TRA-6, Mechanical Damage, had consequence scores in all six of the consequence categories: Health and Safety, Regulatory Compliance, Environment, Financial, Reputation, and Reliability.

See the Risk Register (TURN_01-Q01Atch03CONF), Columns E through J of the "Summary Risk Scores" tab for the consequence scores of each risk in each category.

EXHIBIT JAL/CDF-15

GTS-RateCase2015_DR_ORA_17 -Q008

PACIFIC GAS AND ELECTRIC COMPANY
Gas Transmission and Storage Rate Case 2015
Application 13-12-012
Data Response

PG&E Data Request No.:	ORA_017-08		
PG&E File Name:	GTS-RateCase2015_DR_ORA_017-Q08		
Request Date:	March 3, 2014	Requester DR No.:	ORA-GT&S-17
Date Sent:	April 1, 2014	Requesting Party:	Office of Ratepayer Advocates
PG&E Witness:		Requester:	Jonathan Bromson

SUBJECT: GTS-RATECASE2015_DR_TURN_001- Q01ATCH02, "METHOD FOR CALCULATING WEIGHTED RISKS AND DETERMINING THE HEAT MAP"

QUESTION 8

PG&E states: "The weighing of the consequence levels has to be done on the basis of the values as mentioned in table 1. However this results in a dilution due to the weighting factors and to a dissatisfying and contra-intuitive result as the overall risk is lower than the original Health and Safety value. To compensate for this effect, the result is divided by the health and safety weight factor."

a. Please explain why the weighting factors mentioned in table 1 results in a "dilution." What does PG&E mean by "dilution"?

b. Please explain what PG&E meant by "a dissatisfying a contra-intuitive result as the overall risk is lower than the original Health and Safety value"?

c. For what "effect" does dividing the result by the health and safety weight factor compensate? Does dividing the result by the health and safety weight factor yield an "intuitive" result? Please explain in full.

d. In Table 3, "The calculation of the weighted risk values," please explain what is meant by the column "Avoiding dilution units." Please define and explain "dilution units."

e. Please provide the underlying formulae and variables PG&E used in creating Table 3.

f. Aside from the adjustment PG&E did to the formulae, is there another alternative approach PG&E considered that did not lead to counter-intuitive results? If so, please provide the notes and documents from those approaches.**ANSWER 8**

As stated in GTS-RateCase2015_DR_ORA_017-Q02, GTS-RateCase2015_DR_ ORA_017-Q02Atch01 describes the five steps to create the consequence score as well as the reasons why those steps were chosen.

a. Dilution is a final risk score that is less than the normalized Health and Safety score. In Table Q8B below, showing an example for risk TRA-6, if PG&E used the sum of the normalized and weighted consequence scores in the risk register entry, the sum of all of the scores (Column F, Row 7 - 12.260) would be less than the logarithmic score for Health and Safety (Column D, Row 1 - 17.257).

b. PG&E designed the risk consequence scoring so that the final consequence score would be at least as high as the normalized Health and Safety consequence score so that Health and Safety would be fully appreciated. See part (a), above.

c. Dividing the health and safety weight factor by 0.3 assures that the final consequence score is at least as high as the normalized Health and Safety score. Since safety is the most important of the consequence categories, it makes sense that a final consequence score would at least result in a Health and Safety consequence score that matched the normalized Health and Safety scores. PG&E believes this conservative approach is appropriate.

   In addition, when viewing the risk register, there is a difference in the consequence values shown on the "Risk Matrix Input Data" and the "Risk Matrix Input Data (ERM Fin)" tabs.[1] The reason for this difference is to further apply conservatism when comparing Financial and H&S consequence scores with the expectation that the final risk ranking places H&S consequences above Financial consequences. Although PG&E weights consequence scores at 30% for each Health and Safety and Financial, PG&E prioritizes Health and Safety over Financial consequences. PG&E adjusted consequence scores where the Financial consequence score could cause the risk to rank higher than one with an equal or greater Safety and Health consequence score.

   In Table Q8A below, row 1 shows the subject matter expert input for the consequence values. Note that the column K result is 23.698. Compare the row 1 example to the row 3 example, where for illustration purposes, the H&S score (Column E) has been flipped with the Financial score (Column J), the Column K result is the same, 23.698. This could lead to a consequence with a higher Financial score being placed on the risk register equally with a consequence that has a lower H&S score. To prevent this situation from occurring, if the Financial Score was initially entered as a lower number than the H&S score, it is increased to match the H&S score (see the row 2 example) in the "Risk Matrix Input Data (ERM Fin)" tab in the Risk Register. Column K in row 2 now shows that the consequence value is 40.867, assuring that it is ranked higher on the Risk Register than the illustrative scenario provided in row 3.

1 See attachment GTS-RateCase2015_DR_TURN_001-Q01Atch03CONF.

The model verifies that the Financial CoF score is at least as high as the H & S CoF to make sure consequences with a higher H&S score are prioritized above consequences with a higher financial score.

TABLE Q8A

Example: TRA6 risk in Transmission Asset Family

Columns in "Risk Matrix Input Data" and "Risk Matrix Input Data (ERM Fin)" Tabs from the Risk Register Excel File

	D	E	F	G	H	I	J	K	Column (D) x Column (K)
	LoF	H&S (30%)	RC (5%)	EI (5%)	Rel (25%)	Rep (5%)	Fin (30%)	Normalized Weighted Avoided Dilution Consequence Value	Risk Score
(1) Values in the "Risk Matrix Input Data " tab	0.011	6	5	5	5	6	3	23.698	0.26
(2) Values in the "Risk Matrix Input Data (ERM Fin)" tab	0.011	6	5	5	5	6	6	40.867	0.45
(3) Further illustration of how H&S scores always drive value in overall risk score (Column D x Column K)	0.011	3	5	5	5	6	6	23.698	0.26

d. The "Avoiding Dilution Units" applies to the methodology documented in Table Q8A where the adjusted consequence units are divided by the H&S factor of 0.3, i.e., Adjusted Consequence Units / H&S Factor (0.3) = "Avoiding dilution units." This is to ensure that the overall consequence value is not 'diluted' as explained in Response 8a and 8c.

e. See excel file GTS-RateCase2015_DR_ORA_017-Q04Atch01 for the underlying formulas and variables used to create Table 3. Additionally, they are shown below for all of the calculations in row 1 of the excel file GTS-RateCase2015_DR_ORA_017-Q04Atch01.

Translating to a Logarithmic Scale (Normalizing) – Column D, Row 1
17.25790304=0.000455948900966988*EXP(1.7569*H&S Score of 6). In this case "EXP" is the constant "E" to the power of the numbers by which it is multiplied. "E" is approximately 2.72.

Normalized and Weighted Consequence Score – Column F, Row 1

5.177370913 = 17.25790304 x .3

Avoiding Dilution – Column G, Row 1

17.2579034 = 5.177370913/.3

f. PG&E Gas Operations did not consider another alternative and chose the current methodology to stay consistent with the overall corporate weighting system.

EXHIBIT JAL/CDF-16

GTS-RateCase2015_DR_IS_09-Q006

PACIFIC GAS AND ELECTRIC COMPANY
Gas Transmission and Storage Rate Case 2015
Application 13-12-012
Data Response

PG&E Data Request No.:	IndicatedShippers_009-06		
PG&E File Name:	GTS-RateCase2015_DR_IndicatedShippers_009-Q06		
Request Date:	July 14, 2014	Requester DR No.:	009
Date Sent:	July 24, 2014	Requesting Party:	Indicated Shippers
PG&E Witness:	Bennie Barnes	Requester:	Evelyn Kahl

QUESTION 6

Regarding PG&E Testimony Page 4A-55, lines 20, please provide the analysis PG&E prepared to determine that a 20 mile per year vintage pipe replacement program was "the right pace for reducing these interacting threats." Please include in electronic format all documents, data, and workpapers PG&E used to determine why this should be the correct pace.

(a) Please explain in detail the cost-effectiveness of PG&E's proposed 2015-2017 Vintage Pipeline Replacement program. Please include in electronic format all documents, data, and workpapers PG&E used to determine the cost-effectiveness of the program.

(b) Please provide all empirical analysis PG&E prepared showing how this annual replacement would change the (LoF x Cof) risk values PG&E determined for such vintage pipe and plotted on the Transmission Pipe Heat Map in the Risk Register. Please include the all of the individual LoF and Cof determinants, as they are set out in the "Methodology for calculating weighted risks and determining the Heat Map" provided as Attachment 2 to PG&E's response to TURN_001-01.

ANSWER 6

Please refer to page 4A-55 in the 2015 Gas Transmission and Storage (GT&S) Rate Case testimony where PG&E states, "We determined that 20 miles of pipeline replacement per year is the right pace for reducing risk for these interacting threats during the rate case period because we are able to reduce risk to 90 percent of the population in the vicinity of our pipelines." Note that the segments identified in workpapers on page WP 4A-711 and WP 4A-712 achieve this objective during the 2015 Rate Case period.

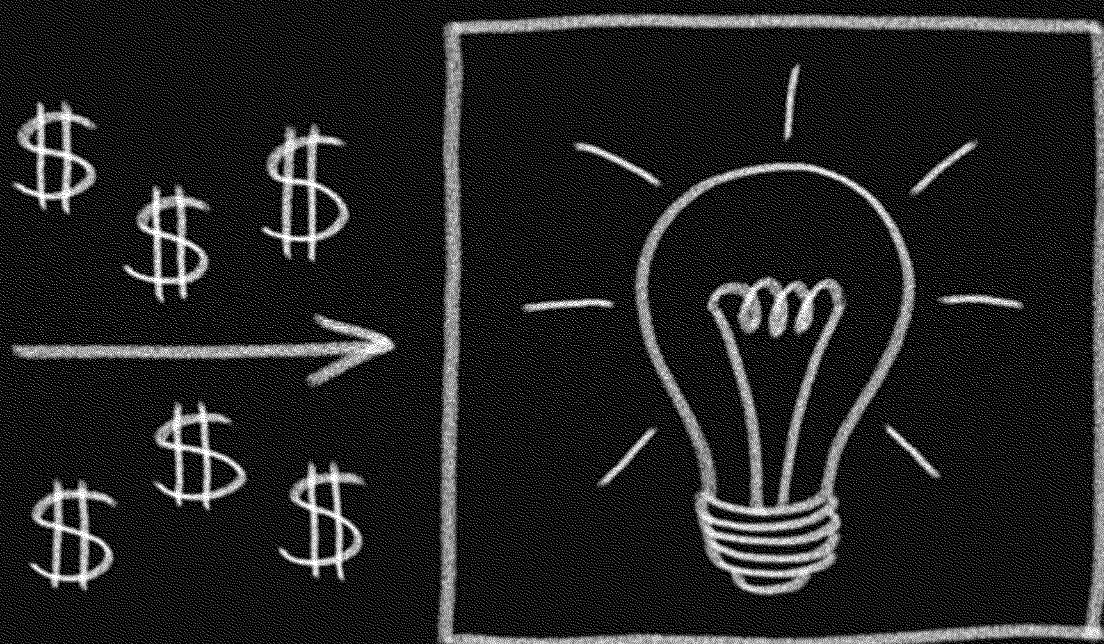
(a) PG&E plans to implement all cost effectiveness measures developed in its Pipeline Safety Enhancement Plan (PSEP) and has captured that in its cost calculator on page WP 4A-722.

(b) PG&E did not perform this high level change analysis, and, therefore cannot provide this empirical analysis.

EXHIBIT JAL/CDF-17

Opening the Black Box, Public Utilities Fortnightly

Opening the Black Box



A new approach to utility asset management.

By Charles D. Feinstein and Jonathan A. Lesser

Natural gas and electric utilities have always been concerned about reliability and safety, and each year spend billions of dollars repairing and replacing transmission and distribution assets. However, unlike the commodities they sell, there are no markets to value safety and reliability. Utilities can't purchase these attributes directly, but instead must determine the best targets for each, while constrained by available resources. There are no guarantees. No system is 100 percent safe or reliable. No amount of planning or investment can completely eliminate sudden, unplanned equipment failures.

In fact, reliability and safety share characteristics of public goods. Customers along a specific distribution line, for example, can't choose different levels of reliability; it's the same for all of them. Thus, utilities must somehow determine how best to provide needed safety and reliability at the lowest possible cost. And state utility regulators must be able to evaluate those determinations accurately and independently.

Many utilities have developed their own methods to address the inevitability of equipment failure and evaluate the tradeoffs between replacing and repairing aging assets. Others rely on methods developed by consultants. Some of these methods are simply *ad hoc* – *e.g.*, "replace utility poles that are 30 years old" or "test underground distribution lines every five years." And these *ad hoc* rules can, in some cases, appear to work well. Yet they aren't based on sound engineering and economic principles. Utilities that employ such rules can't know whether they provide a least-cost strategy. Furthermore, such rules are less likely to pass the heightened regulatory scrutiny that comes when budgets are stretched. In other cases, utilities rely on flawed analytical tools. These tools, while not *ad hoc*, can lead to worse decisions, if flaws appear in underlying assumptions or analytical approaches.

Although the comprehensiveness of these methods varies, they all lead to inefficient or, worse, incorrect, decisions. In other words, utilities can end up spending more money than needed to achieve desired levels of safety and reliability. Or, they obtain less reliability and safety than their methodologies claim to provide. In either case, both ratepayers and utility shareholders lose: with ratepayers paying more and investors seeing lower returns if certain investments are disallowed by regulators.

With natural gas and electric utilities spending billions each year on transmission and distribution systems, both for new equipment and repairs to the old, even small improvements in asset management strategies can yield significant savings for consumers, while maintaining or improving overall reliability and safety. Here we introduce an approach that avoids errors common to other asset management approaches. Our methodology combines advanced statistical and mathematical optimization techniques. It recognizes the interdependence between asset management strategies and testing regimes. It also recognizes interdependencies among assets themselves and avoids the errors common to other asset management approaches.

For utilities and their shareholders, our methodology can provide greater assurance that asset management decisions are prudent, so that the costs can be recovered from ratepayers, thus reducing uncertainty. For utility regulators, the methodology provides greater assurance that utilities are providing required levels of safety and reliability at the lowest cost, thus benefitting ratepayers. Moreover, the methodology can also provide regulators with an objective ability to independently verify utility asset management strategies, rather than accept black-box approaches they can't assess independently.

> Some methods are *ad hoc:* test underground lines every five years, replace utility poles after 30 years.

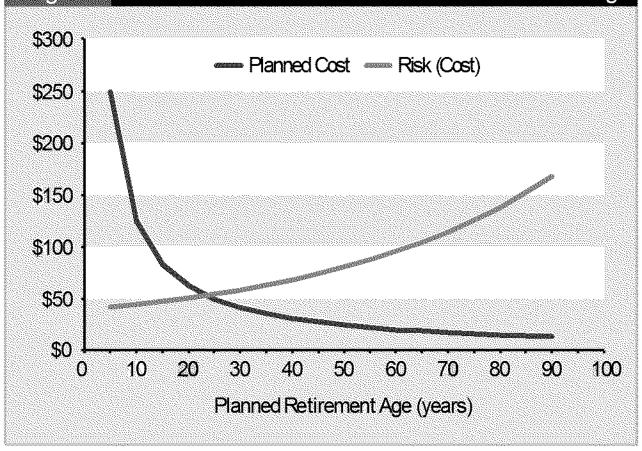
First, we describe six common errors in models used to make asset management decisions for transmission and distribution (T&D), and how these errors lead to inferior decisions about equipment repair and replacement. Second, we explain the four uncertainties that increase the complexity of asset management strategies. Third, we describe the analytical method we developed that addresses these uncertainties in a statistically and mathematically correct way. We conclude with a real-world application of the methodology, showing how it's been used by one regional transmission organization (RTO) to evaluate optimal numbers and locations of spare transformers.

Charles D. Feinstein is an associate professor of operations management and information systems at Santa Clara University and the CEO of VMN Group, LLC. **Jonathan A. Lesser** is the president of Continental Economics, Inc.

The Cost-Risk Tradeoff

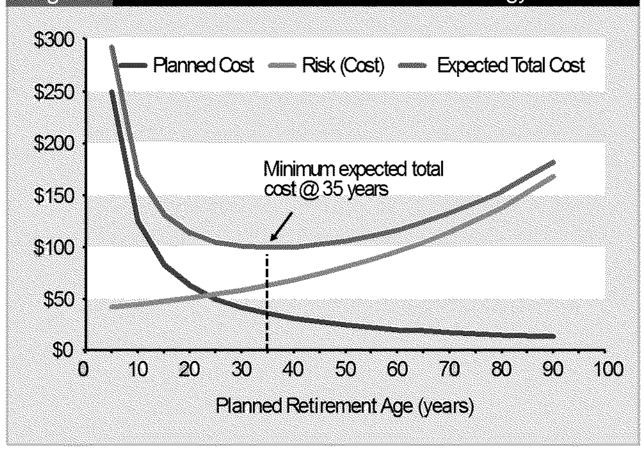
Decisions regarding whether to repair or replace specific assets, or simply leave them in place, share common characteristics and

Fig. 1 Present Value Costs Vs. asset retirement age



Source: Author's analysis

Fig. 2 OPtimal retirement Strategy



Source: Author's analysis

tradeoffs. The basic tradeoff is well-known to anyone who owns a car: putting off replacement to postpone the cost of buying a new one must be tempered against the increasing cost of likely repairs. For utilities, which operate assets over the indefinite future, an asset management strategy based on extending the life of an asset reduces the present value of the cost of asset replacement over the indefinite and foreseeable future. However, as assets age, they tend to require more expensive and more frequent repairs. Further, taken to its logical conclusion, extending the life of an asset tends to provide a "run-to-failure" asset management strategy. Therefore, evaluation of life extension or run-to-failure strategies must address the cost of unplanned failures. These concepts are illustrated in Figure 1.

Figure 1 illustrates the decreasing present value cost associated with planned asset replacements as a function of asset retirement age: the greater the age at which an asset is retired, the lower the present value cost of a timed sequence of asset replacements over the indefinite future. However, as an asset's retirement age increases, the higher the risk (and unplanned costs) associated with repairs or asset failure that could occur in each increasingly large replacement cycle. The costs shown are only expected values, because when (or if) an asset fails is uncertain. The likelihood of an asset's failure sometime in the future is called the asset's "hazard rate."[1]

The optimal retirement age is defined as the one for which the expected total cost is minimized. This is shown in Figure 2. The expected total cost is the sum of the planned replacement costs and the expected cost of asset failures (risk). In the example presented in Figure 2, the minimum expected cost occurs at a planned retirement age of 35 years for this type of asset.[2]

Defining and identifying the optimal replacement strategy is conceptually straightforward, as shown in Figure 2. However, it turns out that Figure 2 illustrates the flaws of commonly applied methods. The reason is that Figures 1 and 2 can't be used in practice to find the optimal retirement age for an asset. In other words, one can't simply construct the two curves and read off the optimal retirement age. Yet, this is commonly done, based on four incorrect assumptions: 1) the time interval between replacements is always the same; 2) all replacement life-cycles cost the same; 3) the actual timing of asset replacements within each replacement life cycle is always the same; and 4) the actual capital costs of asset replacement due to unplanned failures aren't considered, leading to underestimates of actual capital costs.

For one RTO, a key problem was step-down transformers: Refurbish? Replace? Deploy spares?

Some Common Mistakes

We have also identified at least six common types of errors present in many commonly applied asset management methodologies (sometimes also called "repair or replace") that lead to inferior solutions. These common errors include: 1) ignoring or wrongly defining the initial conditions of assets being evaluated; 2) using a misleading concept of "asset health" to lump different classes of assets together; 3) applying a static method (*i.e.,* one that doesn't recognize how the condition of an asset changes over time), based on asset health, to determine how to treat an asset; 4) conflating asset condition with the

1. The hazard rate, $h(t)$, measures the probability that an asset will fail shortly after time t, given that it's survived until time t. The hazard rate can be found empirically by estimating the survivor rate, $S(t)$, which is the probability that an asset survives until at least time t. Mathematically, for some small interval Δt that begins at time t, the probability of failure during this small interval of time = $h(t)\,\Delta t$, where $h(t) = [dS(t)/dt]/S(t)$.

2. At the optimal retirement age, the expected present value marginal cost from higher risk equals the expected present value marginal benefit from fewer replacements; i.e., the slopes of the curves are equal in magnitude and opposite in sign. Note that the optimal replacement age generally isn't where the planned cost and risk cost curves cross.

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consequences of asset failure; 5) failing to account for all of the costs of asset failure; and 6) failing to integrate testing policies into an overall asset management strategy.

Any method that fails to assess the initial condition of assets, or assesses them incorrectly, can't possibly identify an appropriate management strategy and, as a consequence, will be *ad hoc*.

Consider, for example, wooden utility poles. Unless a pole has fallen over or is leaning precipitously, it's difficult to determine its condition. A pole might look fine on the outside, but be rotten inside, awaiting the next windstorm or errant automobile to knock it over. A pole replacement strategy based on whether the pole looks "good" on the outside, regardless of its true internal condition, will lead to excessive pole failures, more outages, and higher costs.

And a wooden utility pole tested and found rotten is far more likely to fail at any given time. That is, asset condition determines the likelihood of future failure. This likelihood is known as a "condition-dependent hazard rate." Although a common-sense way to characterize the so-called "health" of an asset is to measure its remaining life, this straightforward idea has been expanded to include many other aspects of an asset into a single measure called "asset health." However, it turns out that the optimal repair-replace strategies for assets having the same health can be quite different.

Typically, asset health measures combine several distinct attributes, such as age and near-term failure likelihood, into a single measure. However, such a single measure can be misleading because different assets with different attributes could have the same asset health. For example, an older, well-maintained transformer, for example, might have a much lower hazard rate than a younger, poorly-maintained one. Thus, these assets determined to have the same overall health might, in fact, need to be treated very differently.

In some cases, the asset health measurement conflates both the likelihood of near-term failure and the consequences of failure. But that can lead to incorrect conclusions. Consider, for example, a car's tires. Most of us would agree that replacing worn tires before they fail is a better strategy than waiting for a blowout, which can have severe consequences. However, keeping a worn spare tire can be a reasonable strategy because the consequences of tire failure can be managed as well with a worn spare as a brand new spare because both enable one to drive to the nearest tire store. Thus, the asset management policy associated with a tire's condition depends on the tire's intended use, not just the immediate failure rate and the consequences of failure.

Yet another problem is that asset health measures typically fail to account for the dynamics of asset condition; *i.e.*, how an asset's condition changes over time. The condition of an asset changes not only naturally as it ages, but also because of how it's operated and maintained. Again, a car engine is a good example: its condition depends not only on its age, but on how much it's run, whether the car is driven in stop-and-go traffic or primarily on the highway, how frequently the oil is changed, and so forth. Therefore, the asset's hazard rate will change over time as the asset's condition changes. An asset management strategy that assumes the hazard rate doesn't change over time won't be least-cost.[3]

Nor should asset health standing alone dictate asset-management strategy. For example, in some cases, utilities will rank T&D assets by their health and replace those assets in order until the utility reaches a predetermined budget amount. Thus, asset health is treated as if it were a benefit-cost ratio. However, ranking alternatives based on benefit-cost ratios is itself generally inaccurate.[4]

Utilities also might fail to consider all failure costs. For example, widespread power outages can garner negative publicity and additional regulatory scrutiny of a utility's actions. In other cases, such as with the gas pipeline explosion at San Bruno, California, regulators can levy multi-million dollar fines, as the California Public Utilities Commission levied against PG&E.

One can't simply add up the value of spares at each location to determine the value of locating spare transformers at every location.

Finally, asset testing is also crucial to asset management. It's impossible to determine a least-cost asset strategy without also determining the optimal asset testing regime. In other words, asset strategy and testing strategy are interdependent. We have found, for example, that utilities often test too frequently or rely on the wrong kinds of tests. An optimal asset management strategy must account for the outcomes of tests because those outcomes provide information about the true condition of the assets. That's another reason for rejecting a static method of asset management, such as ranking assets by asset health, in favor of a dynamic one that reflects changing conditions over time.

A Dynamic Alternative

These problems lead us to propose an alternative approach – which we call a dynamic optimization methodology to determine asset

3. For those who are mathematically inclined, finding the least-cost strategy over time is known as an "optimal control problem."
4. For a brief discussion, see Leonardo R. Giacchino and Jonathan A. Lesser, *Principles of Utility Corporate Finance*, chapter 17, Public Utilities Reports, Inc., 2011.

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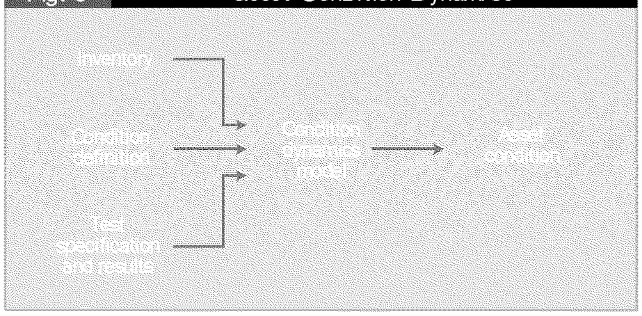
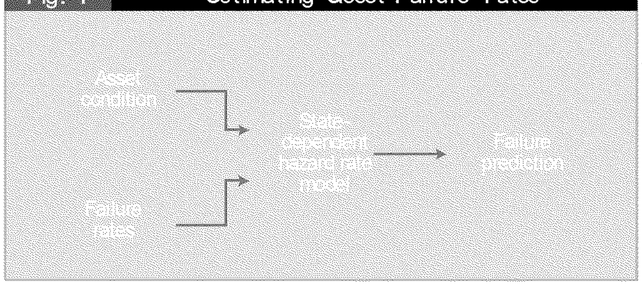
Fig. 3 Asset Condition Dynamics



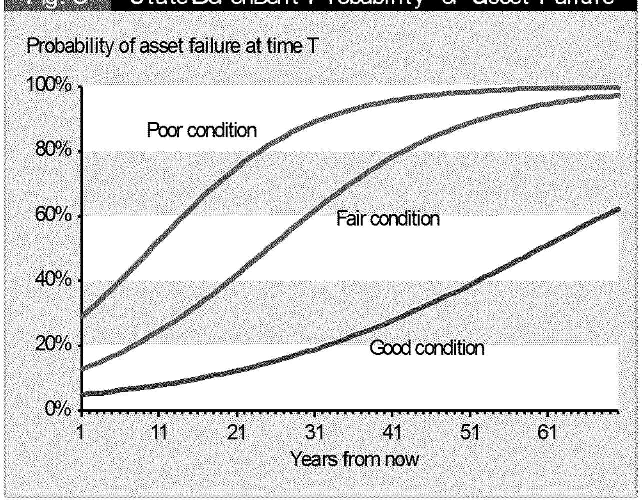
Source: Authors' analysis

Fig. 4 Estimating Asset Failure Rates



Source: Authors' analysis

Fig. 5 State-Dependent Probability of Asset Failure

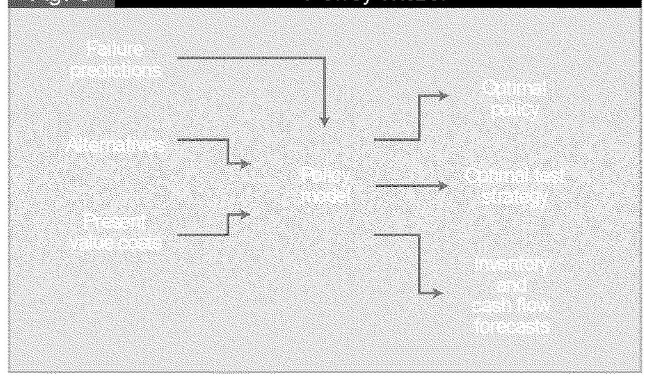


Source: Authors' analysis

strategy.[5] This type of dynamic strategy addresses four types of uncertainty: 1) uncertainty regarding an asset's current condition and how that condition changes over time; 2) uncertainty regarding the accuracy of tests of an asset's condition; 3) uncertainty regarding an asset's remaining life; and 4) uncertainty regarding the effects of repairs on an asset's condition and, therefore, its remaining life.[6]

As we discussed previously, determining an optimal asset management strategy requires that we determine how an asset's condition changes over time, because the condition of an asset at

Fig. 6 Policy Model



Source: Authors' analysis

any time *t* determines the probability of failure thereafter. To do this, we combine condition definitions (e.g., what does it mean for an asset to be in good condition today?) with tests that can evaluate the asset's condition. These are combined to establish what we call a "condition dynamics model (CDM)." The CDM determines how an asset's condition is likely to change over time, given its current condition.[7] (See *Figure 3*).

However, knowing an asset's condition today – unless it's already failed – and the forecast of asset condition given by the CDM won't provide enough information to make asset management (repair, replace, test, do nothing) decisions. That requires a model that estimates the likelihood of asset failure tomorrow, given an asset's condition today. Such models are called State-Dependent Hazard Rate Models, as shown in Figure 4.

Figure 5 illustrates three hazard rates for a class of assets in different condition today.[8] Although it's straightforward to determine a repair-replacement strategy along a single hazard function, that strategy won't be least-cost because we further recognize that repairing an asset can also *change* its condition and thus change the appropriate hazard rate. Depending on the type of repair made, however, there will also be uncertainty as to what is that new post-repair condition.[9]

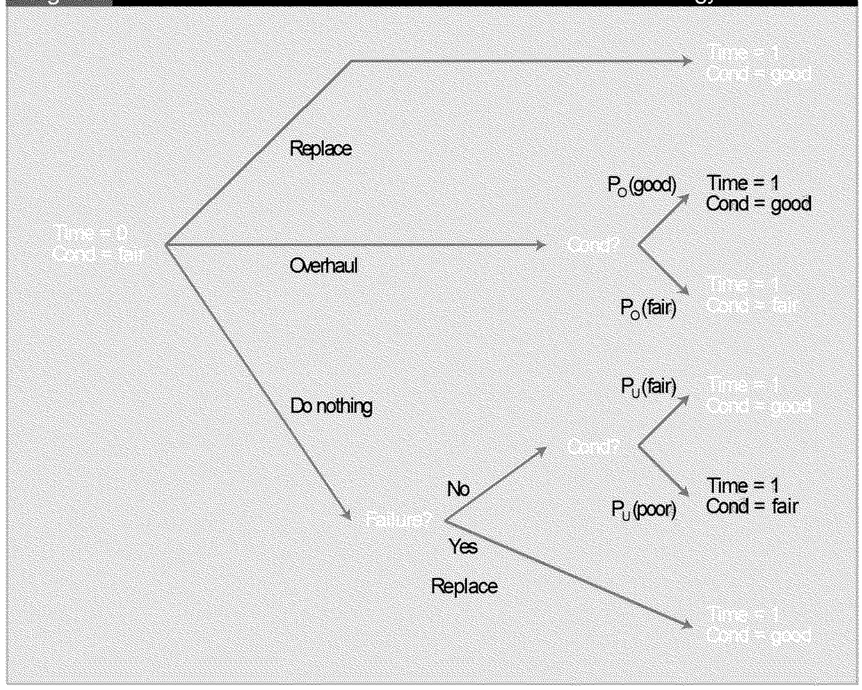
For example, suppose your car is running poorly and you ask the mechanic to change the car engine's oil. Changing the oil will improve the engine's condition because old oil has various contaminants that can increase wear on the various moving parts. However, if the engine has leaking rings or a blown gasket, changing the oil will do little to improve its condition.

5. The Appendix to this article provides a formal mathematical description of the modeling structure. http://www.fortnightly.com/appendix-opening-black-box
6. For further discussion, see Charles D. Feinstein and Peter A. Morris, "The Role of Uncertainty in Managing Aging Assets In Electric Utility Systems," IEEE PES Transmission and Distribution, New Orleans, April 2010. A copy of this presentation is available from the authors.

7. Technically, the CDM establishes a Markov-chain type of probability model, in which we estimate the probability of moving from state A to state B. For example, the probability of a transformer in good condition today being in fair condition next year might be 20 percent, the probability of its being in poor condition next year 5 percent, and the probability of it remaining in good condition 75 percent.
8. The hazard functions are similar in concept to survivor curves used by utilities for depreciation analysis.
9. The post-repair conditions are estimated using a statistical concept called "Bayesian revision." Using the analogy of depreciation survivor curves, repairs can move an asset from one survivor curve to another.

Thus, simple repair can still leave a high level of uncertainty as to the engine's true condition. If, on the other hand, you ask the mechanic to completely rebuild your car's engine, the engine will be in good condition with no uncertainty (assuming the mechanic has rebuilt it correctly). The optimal engine repair strategy, therefore, depends on the type of repair made and the effect of that repair on the engine's condition. Moreover, an optimal strategy must evaluate the tradeoffs between the cost of the repair made and the (uncertain) impact on the engine's post-repair condition.[10]

Fig. 7 SIMPLIFIED DECISION TREE: TRANSFORMER STRATEGY



Source: Authors' analysis

Developing an optimal policy for each class of assets requires additional information, including: 1) the available types of repairs (*e.g.,* major? minor?); 2) the type of replacement asset (*e.g.,* the same asset type? an improved asset?); 3) the costs of the different alternatives; and 4) the probability distribution of the cost of failure. Moreover, the optimal policy includes determining the optimal testing policy, based on the accuracy and the cost of alternative testing regimes. Thus, the Policy Model, shown in Figure 6, can determine the optimal policy as well as the expected benefit of alternative testing regimes. The Policy Model also forecasts the behavior of the asset inventory and the cash flows associated with implementing the optimal policy.

The Policy Model can be envisioned as a type of decision tree. For example, suppose we have a high-voltage transformer, which we believe is in fair condition today (Time = 0). The transformer can be replaced, overhauled, or simply left alone (the "Do Nothing" alternative), as shown in Figure 7.

In the figure, after overhauling or doing nothing, there will remain uncertainty as to the transformer's actual condition at Time = 1. Specifically, if the transformer is overhauled, its condition either will be good with probability PO (good) or fair with probability PO (fair).[11] However, if the transformer is left alone and doesn't fail, next period it will be either in fair condition with probability PN (fair) or poor condition with probability PN (poor). The relative likelihoods of the resulting conditions in the Do-Nothing case are determined by the Condition Dynamics Model. The relative likelihoods associated with the overhauling procedure are based on utility-specific or industry-wide knowledge of the outcomes of overhauling

In actuality, of course, we are dealing with multiple uncertainties, including whether to test the transformer's condition and, if so, what type of test to undertake. Moreover, the time horizon used by the model is infinite. The actual model uses dynamic optimization techniques to solve the model for each asset class and develop a recommended strategy, including a testing strategy. Moreover, the model can estimate the value of different testing regimes.

Spare Transformer Inventory Analysis

One aspect of ensuring a reliable electric system is quick restoration from forced outages. This type of repair-replace decision involves the value of spare equipment, similar to the spare tire example discussed above, with an additional geographical component.

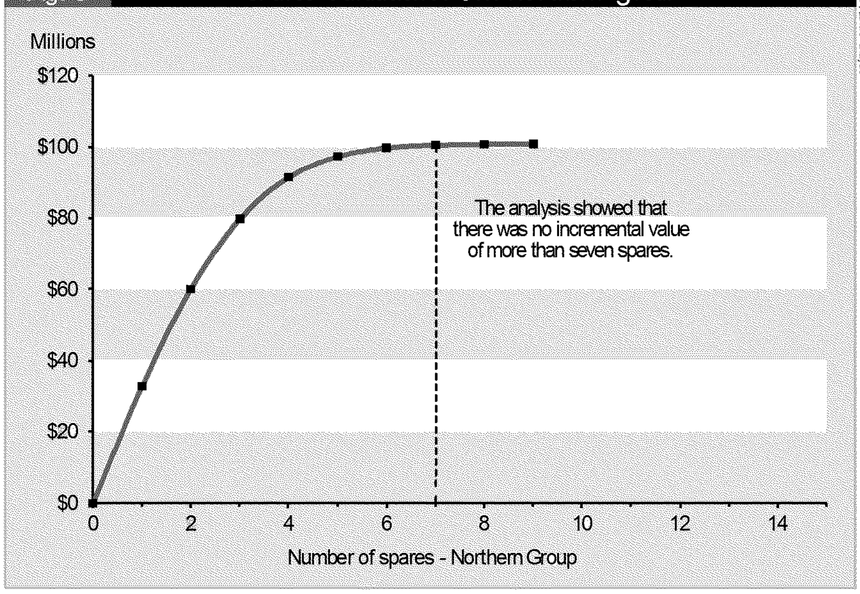
For one RTO, a key issue was the best management policy for the step-down transformers on its system, which reduce voltages from 500 kV to 230 kV. Specifically, the RTO had four questions: 1) how often should these transformers be tested? 2) when should they be overhauled (refurbished)? 3) when should they be replaced? and 4) where should spare transformers be deployed to mitigate the consequences of transformer failures?

The expected value of a spare at a given location within the RTO is based on several factors. Not surprisingly, the first factor is the expected value of reduced outage duration. Thus, if the cost of a forced outage at location X is $\$O_X$ per hour, then the expected value of the spare, $E(V_{S,X})$, equals the probability of failure, $P_X(f)$, times the expected reduction in outage time because of locating the spare at X, ΔT_X, times the outage value, *i.e.*, $E(V_{S,X}) = Px(f) \cdot \Delta T_X \cdot \$0_X$.

10. From a technical standpoint, these impacts are dealt with by the CDM.

11. In this example, P_O (fair) = 1 – P_O (good).

Fig. 8 Spares Valuation: PJM Northern Group



Source: Authors' analysis

In addition to this value, however, a spare will have additional incremental value in one area if it can mitigate the consequences of transformer failure elsewhere. This means one can't simply add up the expected value of spares at each location to determine the overall expected value of locating spare transformers at every location. For example, if a transformer at location X fails, but transformers in nearby locations A, B, and C can handle the additional loads, then the value of a spare transformer at X will be reduced if there are already spares located at A, B, and C.

For the RTO analysis, step-down transformers were grouped into geographic areas. For example, the "Northern Group" consisted of transformers at 18 separate substations. To mitigate failure risk, the RTO had located one spare transformer at each of the substations.

The value of locating a first spare at each location was then calculated. The analysis showed that locating a spare at "Lovell" [12] had a net expected value of $29.5 million,[13] larger than the incremental values at any other location. Moreover, the analysis showed that, because siting a first spare at Lovell also provided additional risk mitigation benefits in the event of transformer failures at other locations, the overall expected net benefit of siting the first spare at Lovell was $32.8 million.

Next, the analysis determined the optimal location of siting a second spare, given that the first spare was already sited at Lovell. This analysis showed that siting a second spare at "Elgin" had an expected value of $27.4 million. The process continued, each time calculating the incremental expected value provided by the next spare, given the spares that had been sited. In total, the analysis showed that there was no incremental benefit to siting more than seven spares in the entire group, as shown in Figure 8. Moreover, the analysis determined that locating a second spare at Elgin had greater value than siting a first spare at many other locations in the Northern Group. Thus, rather than using 18 spares, one at each location, the analysis freed up 11 spares, which the RTO then relocated. In fact, approximately two weeks after the RTO relocated one of the redundant spares to a location in a different transformer group, as recommended by a subsequent analysis, the existing transformer at that substation failed. Because of the location recommendation, the RTO was able to restore service far more quickly and minimize the consequences of the transformer's failure.

Any method that fails to assess the initial condition of assets, or assesses them incorrectly, can't possibly identify an appropriate management strategy.

12. The names of the locations, as well as the characterization of the "Northern Group," are for convention only. The actual substation locations are confidential.
13. This value includes the cost of locating the spare at Lovell.

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